Image Project Order File Cover Page

XHVZE

This page identifies those items that were not scanned during the initial production scanning phase. They are available in the original file, may be scanned during a special rescan activity or are viewable by direct inspection of the file.

O 060 **Order File Identifier**

Organizing (done)

☑ Two-sided

☐ Rescan Needed

RESCAN

☐ Color Items:

☐ Greyscale Items:

☐ Poor Quality Originals:

☐ Other:

DIGITAL DATA

☐ Diskettes, No.

☐ Other, No/Type:

OVERSIZED (Scannable)

☐ Maps:

☐ Other Items Scannable by a Large Scanner

OVERSIZED (Non-Scannable)

☐ Logs of various kinds:

☐ Other::

NOTES:

BY: Maria Date: 7/2/10 /s/ MP

Project Proofing

BY: Maria Date: 7/2/10 /s/ MP

Scanning Preparation ____ x 30 = ____ + ____ = TOTAL PAGES 199

(Count does **not** include cover sheet)

BY: Maria Date: 7/2/10 /s/ MP

Production Scanning

Stage 1 Page Count from Scanned File: 200 (Count **does** include cover sheet)

Page Count Matches Number in Scanning Preparation: ✓ YES ____ NO

BY: Maria Date: 7/2/10 /s/ MP

Stage 1 If *NO* in stage 1, page(s) discrepancies were found: ____ YES ____ NO

BY: Maria Date: /s/

Scanning is complete at this point unless rescanning is required.

ReScanned

BY: Maria Date: /s/

Comments about this file: Quality Checked

10/6/2005 Orders File Cover Page.doc

INDEX OTHER ORDER NO. 60

1.	January 26, 2010	Meme re: Regulations File Opening Commingling of Production Practices
2.	January 26, 2010	Notice of Hearing, Affidavit of Publication
3.	February 10, 2010	E-mail re: Proposed Change to AAC 25.215
4.	March 18, 2010	Public Hearing Transcript
5.	March 30, 2010	AOGA Letters re: Proposed Changes
6.	May 12, 2010	Final Regulation Package to Attorney General's Office
7.	June 2, 2010	Memo Re: Regulations 20 AAC 25.215 Commingling of Production Practices

Other Order No. 60

Amended Regulations Dealing with Commingling of Production and Injection Practices

The Alaska Oil and Gas Conservation Commission have revised its regulations dealing with commingling of production and injection practices requirements in 20 AAC 25.215. The amended regulation accounts for commingling injected well fluids. The Lieutenant Governor signed and filed the regulation changes on June 7, 2010, with an effective date of July 7, 2010.

For further information or to obtain a copy of the amended regulations, contact Jody Colombie at (907) 793-1221, fax (907) 276-7542, or e-mail jody.colombie@alaska.gov.

20 AAC 25.215 is amended to read:

20 AAC 25.215 Commingling of production and injection into two or more pools. (a) On the surface, the production from one pool may not be commingled with that from another pool except if the quantities from each pool are determined by monthly well tests or by another method of determining pool production approved by the commission.

(b) Commingling of production within the same wellbore from two or more pools is not permitted unless, after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission

(1) finds that waste will not occur, and that production from separate pools can be properly allocated; and

(2) issues an order providing for commingling for wells completed from these pools within the field.

(c) Injection into two or more pools within the same wellbore is not permitted unless, after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission

(1) finds that the proposed injection activity will not result in waste or damage to a pool, and that injection volumes can be properly allocated; and

(2) issues an order providing for injection into wellbores completed to allow for simultaneous injection into two or more pools.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am 11/7/99, Register 152; am 07/07/2010, Register, 195)

Authority: AS 31.05.030 **<u>AS 31.05.095</u>**

ORDER CERTIFYING THE CHANGES TO
REGULATIONS OF ALASKA OIL AND GAS CONSERVATION
COMMISSION

The attached 1 page of regulations, dealing with commingling of production under 20 AAC 25, is certified to be a correct copy of the regulation changes that the Alaska Oil and Gas Conservation Commission adopted at its May 5, 2010 meeting, under the authority of AS 31.05.030 and AS 31.05.040 and in compliance with the Administrative Procedure Act (AS 44.62), including the notice provisions (AS 44.62.190 and AS 44.62.200) and opportunity for public comment provision (AS 44.62.210).

This action is not expected to require an increased appropriation.

On the record, in considering public comments, the Alaska Oil and Gas Conservation Commission paid special attention to the cost to private persons of the regulatory action being taken.

As provided in AS 44.62.180, the subject regulation changes take effect on the 30th day after they are filed by the lieutenant governor.

DATE: May 28, 2010
Anchorage

Daniel T. Seamount, Jr.
Commissioner, Chair

FILING CERTIFICATION

I, Scott Clark for Craig E. Campbell, Lieutenant Governor for the State of Alaska, certify that on June 7, 2010 at 4:04 p.m., I filed the attached regulations according to the provisions of AS 44.62.040 – 44.62.120.

Scott Cl for
Lieutenant Governor Craig E. Campbell

Effective: July 7, 2010

Register: 195, October 2010

20 AAC 25.215 is amended to read:

i t m p

20 AAC 25.215 Commingling of ~~P~~roduction <u>and ~~I~~njection into ~~T~~wo or ~~M~~ore ~~P~~ools</u>.

p

(a) On the surface, the production from one pool may not be commingled with that from another pool except if the quantities from each pool are determined by monthly well tests or by another method of determining pool production approved by the commission.

Publisher: Text of subsecs. (a) and (b) are unchanged. DEB

(b) Commingling of production within the same wellbore from two or more pools is not permitted unless, after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission

(1) finds that waste will not occur, and that production from separate pools can be properly allocated; and

(2) issues an order providing for commingling for wells completed from these pools within the field.

(c) Injection into two or more pools within the same wellbore is not permitted unless, after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission

(1) finds that the proposed injection activity will not result in waste or damage to a pool, and that injection volumes can be properly allocated; and

(2) issues an order providing for injection into wellbores completed to allow for simultaneous injection into two or more pools.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am 11/7/99, Register 152; am 7/7/2010, Register, 195)

bold

Authority: AS 31.05.030, AS 31.05.095

Craig E. Campbell
Lieutenant Governor
State Capitol
Juneau, Alaska 99811
907.465.3520 465.5400 Fax
WWW.LTGOV.ALASKA.GOV

530 West 7th Ave, Suite 1700
Anchorage, Alaska 99501
907.269.7460 269.0263
LT.GOVERNOR@ALASKA.GOV

OFFICE OF THE LIEUTENANT GOVERNOR
ALASKA

MEMORANDUM

TO: Robert Pearson, AAC Contact
Department of Administration

FROM: Scott Clark
Special Assistant
907.465.4081

DATE: June 8, 2010

RE: Filed Permanent Regulations: Alaska Oil and Gas Conservation Commission

Commingling of Production Practices: 20 AAC 25.215

Attorney General File:	JU2010201083
Regulation Filed:	6/7/2010
Effective Date:	7/7/2010
Print:	195, October 2010

cc with enclosures: Linda Miller, Department of Law
Jim Pound, Administrative Regulation Review Committee
Judy Herndon, LexisNexis

#7

MEMORANDUM

State of Alaska
Department of Law

To: Daniel T. Seamount, Chair
Alaska Oil and Gas Conservation
Commission
Dept. of Administration

Date: June 2, 2010

File No.: JU2010201083

Tel. No.: 465-3600

From: Deborah E. Behr
Chief Assistant Attorney General
and Regulations Attorney
Legislation and Regulations Section

Re: Regulations re: 20 AAC 25.215: Commingling of Production Practices

Under AS 44.62.060, we have reviewed the Alaska Oil and Gas Conservation Commission adoption and amendment of the regulations and approve the changes for filing by the lieutenant governor. A duplicate original of this memorandum is being furnished the lieutenant governor, along with the 1 page of regulations and the related documents.

You might wish to contact the lieutenant governor's office to confirm the filing date and effective date of the attached regulation changes.

The January 26, 2010 public notice and the May 28, 2010 certification order both state that this action is not expected to require an increased appropriation. Therefore, a fiscal note under AS 44.62.195 is not required.

In accordance with AS 44.62.125(b)(6), some corrections have been made in the regulations, as shown on the attached copy.

DEB:pav

cc w/enc.:

Robert Pearson, Regulations Contact
Dept. of Administration

Jody Colombie, Special Assistant
Alaska Oil and Gas Conservation Commission
Dept. of Administration

Tom Ballantine, Assistant Attorney General
Anchorage

20 AAC 25.215 is amended to read:

20 AAC 25.215 Commingling of ~~P~~roduction and ~~I~~njection into ~~T~~wo or ~~M~~ore ~~P~~ools.

(a) On the surface, the production from one pool may not be commingled with that from another pool except if the quantities from each pool are determined by monthly well tests or by another method of determining pool production approved by the commission.

Publisher: Text of subsecs. (a) and (b) are unchanged. DEB

(b) Commingling of production within the same wellbore from two or more pools is not permitted unless, after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission

(1) finds that waste will not occur, and that production from separate pools can be properly allocated; and

(2) issues an order providing for commingling for wells completed from these pools within the field.

(c) Injection into two or more pools within the same wellbore is not permitted unless, after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission

(1) finds that the proposed injection activity will not result in waste or damage to a pool, and that injection volumes can be properly allocated; and

(2) issues an order providing for injection into wellbores completed to allow for simultaneous injection into two or more pools.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am 11/7/99, Register 152; am ___/___/____, Register, ____)

Authority: AS 31.05.030 AS 31.05.095 bold

#6

MEMORANDUM

STATE OF ALASKA

ALASKA OIL AND GAS CONSERVATION COMMISSION

TO: Regulations Attorney
Legislation/Regulations Section
Department of Law

DATE: May 12, 2010

SUBJECT: AG File No. JU2010201083
Request for Legal Review
of Regulations Project on
Commingling of Production
and Injection Practices
20 AAC 25.215

FROM: Daniel T. Seamount, Jr., Chair
Regulations Contact
Department of Administration

We are requesting approval of the attached final regulations on the Commingling of Production and Injection Practices. The Commission adopted these changes on May 5, 2010.

Enclosed are the following documents:

1. original and one copy of the final regulations;
2. original signed and dated certification order;
3. original public notices;
4. original additional regulations notice information form distributed with the notice;
5. original publisher's affidavit's of publication;
6. original affidavit of notice;
7. original affidavit of oral hearing;
8. original affidavit of commission action;
9. excerpt from unapproved minutes from the May 5, 2010 meeting;

We worked with Assistant Attorney General Thomas Ballantine on this project.

Upon completing your review, please forward the regulations to the lieutenant governor for filing. In accordance with AS 44.62.180, the regulation changes will take effect on the 30th day after filing.

ORDER CERTIFYING THE CHANGES TO REGULATIONS OF ALASKA OIL AND GAS CONSERVATION COMMISSION

The attached 1 page of regulations, dealing with commingling of production under 20 AAC 25, is certified to be a correct copy of the regulation changes that the Alaska Oil and Gas Conservation Commission adopted at its May 5, 2010 meeting, under the authority of AS 31.05.030 and AS 31.05.040 and in compliance with the Administrative Procedure Act (AS 44.62), including the notice provisions (AS 44.62.190 and AS 44.62.200) and opportunity for public comment provision (AS 44.62.210).

This action is not expected to require an increased appropriation.

On the record, in considering public comments, the Alaska Oil and Gas Conservation Commission paid special attention to the cost to private persons of the regulatory action being taken.

As provided in AS 44.62.180, the subject regulation changes take effect on the 30th day after they are filed by the lieutenant governor.

DATE: May 28, 2010
Anchorage

Daniel T. Seamount, Jr.
Commissioner, Chair

FILING CERTIFICATION

I, Craig E. Campbell, Lieutenant Governor for the State of Alaska, certify that on ________________, 2010 at __________ .m., I filed the attached regulations according to the provisions of AS 44.62.040 – 44.62.120.

Lieutenant Governor

Effective: ________________.

Register: ________________.

STATE OF ALASKA)
) ss.
THIRD JUDICIAL DISTRICT)

AFFIDAVIT OF COMMISSION ACTION

I, Jody J. Colombie, Special Assistant to the Alaska Oil and Gas Conservation Commission, being sworn, state the following:

The attached motion, dealing with commingling of production practices regulation changes, was passed by the Alaska Oil and Gas Conservation Commission during its May 5, 2010 meeting.

Date: May 12, 2010
Anchorage

Jody J. Colombie

Jody J. Colombie
Special Assistant to the Commission

SUBSCRIBED AND SWORN TO before me this 12th day of May, 2010.

Linda K. Laasch

Notary Public in and for the
State of Alaska
My commission expires: 11/11/2010

ALASKA OIL AND GAS CONSERVATION COMMISSION MEETING
May 5, 2010 Unapproved Minutes

Commissioner John K. Norman moved and Commissioner Cathy P. Foerster seconded the following motion:

"I move to adopt the attached draft amendment to 20 AAC 25.215."

The motion carried unanimously.

STATE OF ALASKA)
) ss.
THIRD JUDICIAL DISTRICT)

AFFIDAVIT OF ORAL HEARING

I, Jody J. Colombie, Special Assistant to the Alaska Oil and Gas Conservation Commission, being sworn, state the following:

On March 18, 2010, at 9:00 a.m., at 333 West 7th Avenue, Suite 100, Anchorage, Alaska, a public hearing presided over by Daniel T. Seamount, Jr., Commissioner, Chair of the Alaska Oil and Gas Conservation Commission, was held in accordance with AS 44.62.210 for the purpose of taking testimony in connection with the adoption of changes to 20 AAC 25.215, dealing with commingling of production practices.

DATE: May 12, 2010
Anchorage, Alaska

Jody J. Colombie
Jody J. Colombie
Special Assistant to the Commission

SUBSCRIBED AND SWORN TO before me this 12th day of May, 2010.

Linda K. Laasch
Notary Public in and for the
State of Alaska
My commission expires: 11/11/2010

STATE OF ALASKA)
) ss.
THIRD JUDICIAL DISTRICT)

AFFIDAVIT OF NOTICE OF PROPOSED ADOPTION OF REGULATIONS AND FURNISHING OF ADDITIONAL INFORMATION

I, Jody J. Colombie, Special Assistant to the Alaska Oil and Gas Conservation Commission, being sworn, state the following:

As required by AS 44.62.190, notice of the proposed adoption of changes to 20 AAC 25.215, dealing with commingling of production practices, was given by being

(1) published in a newspaper or trade publication;
(2) furnished to interested persons as shown on the attached list;
(3) furnished to appropriate state officials;
(4) furnished to the Department of Law, along with a copy of the proposed regulations;
(5) electronically transmitted to incumbent State of Alaska legislators;
(6) furnished to the Legislative Affairs Agency, Legislative Library;
(7) posted on the Alaska Online Public Notice System, as required by AS 44.62.175(a)(1) and (b) and AS 44.62.190(a)(1);
(8) furnished electronically, along with a copy of the proposed regulations, to the Legislative Affairs Agency, the chairs of the Senate Resources Committee and House Special Committee of Oil and Gas, the Administrative Regulation Review Committee, and the Legislative Council.

As required by AS 44.62.190(d), additional regulations notice information regarding the proposed adoption of the regulation changes described above was furnished to interested persons as shown on the attached list and those in (5) and (6) of the list above. The additional regulations notice information was posted on the Alaska Online Public Notice System.

DATE: May 12, 2010
Anchorage

Jody J. Colombie
Jody J. Colombie
Special Assistant to the Commission

SUBSCRIBED AND SWORN TO before me this 12th day of May 2010.

Linda K. Laasch
Notary Public in and for the
State of Alaska
My commission expires: 11/11/2010

20 AAC 25.215 is amended to read:

20 AAC 25.215 Commingling of Production and Injection into Two or More Pools.

(a) On the surface, the production from one pool may not be commingled with that from another pool except if the quantities from each pool are determined by monthly well tests or by another method of determining pool production approved by the commission.

(b) Commingling of production within the same wellbore from two or more pools is not permitted unless, after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission

(1) finds that waste will not occur, and that production from separate pools can be properly allocated; and

(2) issues an order providing for commingling for wells completed from these pools within the field.

(c) Injection into two or more pools within the same wellbore is not permitted unless, after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission

(1) finds that the proposed injection activity will not result in waste or damage to a pool, and that injection volumes can be properly allocated; and

(2) issues an order providing for injection into wellbores completed to allow for simultaneous injection into two or more pools.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am 11/7/99, Register 152; am ___/___/____, Register, ____)

Authority: AS 31.05.030 AS 31.05.095

20 AAC 25.215 is amended to read:

20 AAC 25.215 Commingling of Production and Injection into Two or More Pools.

(a) On the surface, the production from one pool may not be commingled with that from another pool except if the quantities from each pool are determined by monthly well tests or by another method of determining pool production approved by the commission.

(b) Commingling of production within the same wellbore from two or more pools is not permitted unless, after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission

(1) finds that waste will not occur, and that production from separate pools can be properly allocated; and

(2) issues an order providing for commingling for wells completed from these pools within the field.

(c) Injection into two or more pools within the same wellbore is not permitted unless, after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission

(1) finds that the proposed injection activity will not result in waste or damage to a pool, and that injection volumes can be properly allocated; and

(2) issues an order providing for injection into wellbores completed to allow for simultaneous injection into two or more pools.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am 11/7/99, Register 152; am ___/___/____, Register, ____)

Authority: AS 31.05.030 AS 31.05.095

STATE OF ALASKA
RE-NOTICE OF PROPOSED CHANGES IN THE REGULATIONS OF THE ALASKA OIL AND GAS CONSERVATION COMMISSION

The Alaska Oil and Gas Conservation Commission (AOGCC) proposes to adopt changes to Title 20, Chapter 25, of the Alaska Administrative Code, dealing with commingling of production.

AOGCC proposes to add language to 20 AAC 25.215 that will explicitly include commingled injected fluids.

You may comment on the proposed regulation changes, including the potential costs to private persons of complying with the proposed changes, by submitting written comments to the Alaska Oil and Gas Conservation Commission at 333 West 7th Avenue, Suite 100, Anchorage, Alaska 99501. The comments must be received no later than 4:30 p.m. on March 8, 2010.

Oral or written comments also may be submitted at a hearing to be held from 9:00 a.m. to 12:00 p.m. on March 18, 2010, at 333 West 7th Avenue, Suite 100, Anchorage, Alaska 99501. The hearing may continue beyond 12:00 p.m. to allow comment by those present before 9:30 a.m. The public comment period will close at the end of the March 18, 2010 hearing.

If you are a person with a disability who needs a special accommodation in order to participate in this process, please contact Jody Colombie at (907) 793-1221 no later than March 1, 2010 to ensure that any necessary accommodations can be provided.

For a copy of the proposed regulation changes, contact Jody Colombie at 333 West 7th Avenue, Suite 100, Anchorage, Alaska 99501, (907) 793-1221, or go to www.aogcc.alaska.gov.

After the public comment period ends, the Alaska Oil and Gas Conservation Commission will either adopt these or other provisions addressing the same subject, without further notice, or decide to take no action on them. The language of the final regulations may be different from that of the proposed regulations. YOU SHOULD COMMENT DURING THE TIME ALLOWED IF YOUR INTERESTS COULD BE AFFECTED.

Statutory Authority: AS 31.05.030.
Statutes Being Implemented, Interpreted, or Made Specific: AS 31.05.030.
Fiscal Information: The proposed regulation changes are not expected to require an increased appropriation.

DATE: 1/26/10

Daniel T. Seamount, Jr., Chair

ADDITIONAL REGULATIONS NOTICE INFORMATION
(AS 44.62.190(d))

1. Adopting agency: Alaska Oil and Gas Conservation Commission.

2. General subject of regulations: Commingling of Production and injection fluids.

3. Citation of regulations: 20 AAC 25.215(b) and 20 AAC 25.215(b)(1)

4. Reason for the proposed action: to make regulations current with recent technological improvements.

5. Program category and BRU affected: Alaska Oil and Gas Conservation Commission.

6. Cost of implementation to the state agency: Initial and annual costs are zero.

7. The name of the contact person for the regulations:
   Name: Dave Roby
   Title: Senior Reservoir Engineer
   Address: 333 W. 7th Avenue, Suite 100, Anchorage, AK 99501
   Telephone: (907) 793-1221
   E-mail: dave.roby@alaska.gov

8. The origin of the proposed action: agency staff.

9. Date: January 26, 2010

10. Prepared by: Jody Colombie

Jody J. Colombie
Alaska Oil and Gas Conservation Commission
(907) 793-1221

Anchorage Daily News
Affidavit of Publication

1001 Northway Drive, Anchorage, AK 99508

AD #	DATE	PO	ACCOUNT	PRICE PER DAY	OTHER CHARGES	OTHER CHARGES #2	OTHER CHARGES #3	GRAND TOTAL
734181	01/27/2010	AO-03014	STOF0330	$355.24 $355.24	$0.00	$0.00	$0.00	$355.24

STATE OF ALASKA
THIRD JUDICIAL DISTRICT

Shane Drew, being first duly sworn on oath deposes and says that he is an advertising representative of the Anchorage Daily News, a daily newspaper.

That said newspaper has been approved by the Third Judicial Court, Anchorage, Alaska, and it now and has been published in the English language continually as a daily newspaper in Anchorage, Alaska, and it is now and during all said time was printed in an office maintained at the aforesaid place of publication of said newspaper. That the annexed is a copy of an advertisement as it was published in regular issues (and not in supplemental form) of said newspaper on the above dates and that such newspaper was regularly distributed to its subscribers during all of said period. That the full amount of the fee charged for the foregoing publication is not in excess of the rate charged private individuals.

Signed Shane Drew

Subscribed and sworn to me before this date:
FEB 05 2010

Notary Public in and for the State of Alaska.
Third Division. Anchorage, Alaska

MY COMMISSION EXPIRES: 12/17/13

Cynthia A. Grove

CYNTHIA A. GROVE
NOTARY
PUBLIC
STATE OF ALASKA

STATE OF ALASKA
RE-NOTICE OF PROPOSED CHANGES IN THE REGULATIONS OF THE ALASKA OIL AND GAS CONSERVATION COMMISSION

The Alaska Oil and Gas Conservation Commission (AOGCC) proposes to adopt changes to Title 20, Chapter 25, of the Alaska Administrative Code, dealing with commingling of production.

AOGCC proposes to add language to 20 AAC 25.215 that will explicitly include commingled injected fluids.

You may comment on the proposed regulation changes, including the potential costs to private persons of complying with the proposed changes, by submitting written comments to the Alaska Oil and Gas Conservation Commission at 333 West 7th Avenue, Suite 100, Anchorage, Alaska 99501. The comments must be received no later than 4:30 p.m. on March 8, 2010.

Oral or written comments also may be submitted at a hearing to be held from 9:00 a.m. to 12:00 p.m. on March 18, 2010, at 333 West 7th Avenue, Suite 100, Anchorage, Alaska 99501. The hearing may continue beyond 12:00 p.m. to allow comment by those present before 9:30 a.m. The public comment period will close at the end of the March 18, 2010 hearing.

If you are a person with a disability who needs a special accommodation in order to participate in this process, please contact Jody Colombie at (907) 793-1221 no later than March 1, 2010 to ensure that any necessary accommodations can be provided.

For a copy of the proposed regulation changes, contact Jody Colombie at 333 West 7th Avenue, Suite 100, Anchorage, Alaska 99501, (907) 793-1221, or go to www.aogcc.alaska.gov.

After the public comment period ends, the Alaska Oil and Gas Conservation Commission will either adopt these or other provisions addressing the same subject, without further notice, or decide to take no action on them. The language of the final regulations may be different from that of the proposed regulations. YOU SHOULD COMMENT DURING THE TIME ALLOWED IF YOUR INTERESTS COULD BE AFFECTED.

Statutory Authority: AS 31.05.030.
Statutes Being Implemented, Interpreted, or Made Specific: AS 31.05.030.
Fiscal Information: The proposed regulation changes are not expected to require an increased appropriation.

Daniel T. Seamount, Jr.,
Chair

ADDITIONAL REGULATIONS NOTICE INFORMATION
(AS 44.62.190(d))

1. Adopting agency: Alaska Oil and Gas Conservation Commission.

2. General subject of regulations: Commingling of Production and Injection fluids.

3. Citation of regulations: 20 AAC 25.215(b) and 20 AAC 25.215(b)(1)

4. Reason for the proposed action: to make regulations current with recent technological improvements.

5. Program category and BRU affected: Alaska Oil and Gas Conservation Commission.

6. Cost of implementation to the state agency: Initial and annual costs are zero.

7. The name of the contact person for the regulations:
Name: Dave Roby
Title: Senior Reservoir Engineer
Address: 333 W. 7th Avenue, Suite 100, Anchorage, AK 99501
Telephone: (907) 793-1221
E-mail: dave.roby@alaska.gov

8. The origin of the proposed action: agency staff.

9. Date: January 26, 2010

10. Prepared by:
Jody J. Colombie
Alaska Oil and Gas Conservation Commission
(907) 793-1221

AO-03014021
Published: January 27, 2010

SERVICE LIST FOR PROPOSED AMENDMENTS TO 20 AAC 25.215

On January 26, 2010, I mailed to the following individuals the public notice of proposed amendments to 20 AAC 25.215, additional regulations notice information, and proposed regulations:

Annette Kreitzer
Commissioner
Department of Administration
PO Box 110200
Juneau, AK 99811

Debra Behr
Chief Assistant Attorney General
Legislation and Regulations Section
Department of Law
PO Box 110300
Juneau, AK 99811

Colombie, Jody J (DOA)

From: Colombie, Jody J (DOA)
Sent: Tuesday, January 26, 2010 2:23 PM
To: resregs@legis.state.ak.us; (foms2@mtaonline.net); (michael.j.nelson@conocophillips.com); (Von.L.Hutchins@conocophillips.com); alaska@petrocalc.com; Anna Raff; Barbara F Fullmer; bbritch; Becky Bohrer; Bill Walker; Bowen Roberts; Brad McKim; Brady, Jerry L; Brandon Gagnon; Brandow, Cande (ASRC Energy Services); Brian Gillespie; Brian Havelock; Bruce Webb; carol smyth; caunderwood; Charles O'Donnell; Chris Gay; Cliff Posey; Crandall, Krissell; Dan Bross; dapa; Daryl J. Kleppin; David Boelens; David House; David Steingreaber; 'ddonkel@cfl.rr.com'; Deborah J. Jones; doug_schultze; Elowe, Kristin; Evan Harness; eyancy; Francis S. Sommer; Fred Steece; Garland Robinson; Gary Laughlin; Gary Rogers; Gary Schultz; ghammons; Gordon Pospisil; Gorney, David L.; Gregg Nady; gspfoff; Hank Alford; Harry Engel; Jdarlington (jarlington@gmail.com); Jeff Jones; Jeffery B. Jones (jeff.jones@alaska.gov); Jerry McCutcheon; Jim White; Jim Winegarner; Joe Nicks; John Garing; John S. Haworth; John Spain; John Tower; John W Katz; Jon Goltz; Joseph Darrigo; Julie Houle; Kari Moriarty; Kaynell Zeman; Keith Wiles; Laura Silliphant; Marilyn Crockett; Mark Dalton; Mark Hanley (mark.hanley@anadarko.com); Mark Kovac; Mark P. Worcester; Marquerite kremer; Michael Jacobs; Mike Bill; Mike Mason; Mikel Schultz; Mindy Lewis; MJ Loveland; mjnelson; mkm7200; nelson; Nick W. Glover; NSK Problem Well Supv; Patty Alfaro; Paul Decker (paul.decker@alaska.gov); PORHOLA, STAN T; Rader, Matthew W (DNR); Raj Nanvaan; Randall Kanady; Randy L. Skillern; Rob McWhorter; rob.g.dragnich@exxonmobil.com; Robert A. Province (raprovince@marathonoil.com); Robert Campbell; Roberts, Susan M.; Rudy Brueggeman; Scott Cranswick; Shannon Donnelly; Sharmaine Copeland; Shellenbaum, Diane P (DNR); Slemons, Jonne D (DNR); Sondra Stewman; Steve Lambert; Steve Moothart; Steven R. Rossberg; Suzanne Gibson; tablerk; Tamera Sheffield; Taylor, Cammy O (DNR); Ted Rockwell; Temple Davidson; Teresa Imm; Terrie Hubble; Thor Cutler; Todd Durkee; Tony Hopfinger; trmjr1; Walter Featherly; Williamson, Mary J (DNR); Winslow, Paul M; 'Aaron Gluzman'; 'Dale Hoffman'; Frédéric Grenier; 'Gary Orr'; Jerome Eggemeyer; 'Joe Longo'; 'Lamont Frazer'; Marc Kuck; 'Mary Aschoff'; Maurizio Grandi; P Bates; Richard Garrard; 'Sandra Lemke'; 'Scott Nash'; 'Tiffany Stebbins'; 'Wayne Wooster'; 'Willem Vollenbrock'; 'William Van Dyke'; Woolf, Wendy C (DNR); Aubert, Winton G (DOA); Ballantine, Tab A (LAW); Brooks, Phoebe; Crisp, John H (DOA); Darlene Ramirez; Davies, Stephen F (DOA); Foerster, Catherine P (DOA); Grimaldi, Louis R (DOA); Johnson, Elaine M (DOA); Jones, Jeffery B (DOA); Laasch, Linda K (DOA); Mahnken, Christine R (DOA); Maunder, Thomas E (DOA); McIver, Bren (DOA); McMains, Stephen E (DOA); Noble, Robert C (DOA); Norman, John K (DOA); Okland, Howard D (DOA); Paladijczuk, Tracie L (DOA); Pasqual, Maria (DOA); Regg, James B (DOA); Roby, David S (DOA); Saltmarsh, Arthur C (DOA); Scheve, Charles M (DOA); Schwartz, Guy L (DOA); Seamount, Dan T (DOA); Austerman, Alan; Buch, Bob (LAA); Bunde, Con (LAA); Cathy Munoz (Representative_Cathy_Engstrom_Munoz@legis.state.ak.us); Chenault, Mike (LAA); Cissna, Sharon (LAA); Coghill, John (LAA); Crawford, Harry (LAA); Dahlstrom, Nancy (LAA); Davis, Bettye J (LAA); Doogan, Mike (LAA); Dyson, Fred (LAA); Edgmon, Bryce E (LAA); Egan, Dennis W (LAA); Ellis, Johnny (LAA); Fairclough, Anna (LAA); 'Foster, Richard'; French, Hollis (LAA); Gara, Les (LAA); Gardner, Berta (LAA); Gatto, Carl (LAA); Gruenberg, Max F (LAA); Guttenberg, David (LAA); Harris, John (LAA); Hawker, Mike (LAA); Herron, Bob; Hoffman, Lyman F (LAA); Holmes, Lindsey (LAA); Huggins, Charlie (LAA); Johansen, Kyle B (LAA); Johnson, Craig W (LAA); Joule, Reggie (LAA); Kawasaki, Scott Jw (LAA); Keller, Wes (LAA); Kelly, Mike (LAA); Kerttula, Beth (LAA); kevin meyer; Kookesh, Albert (LAA); Lynn, Bob (LAA); McGuire, Lesil L (LAA); Menard, Linda K; Millett, Charisse; Neuman, Mark A (LAA); Olson, Donny (LAA); Olson, Kurt E (LAA); Paskvan, Joe; Petersen, Pete; Ramras, Jay B (LAA); Salmon, Woodie W (LAA); Seaton, Paul (LAA); Stedman, Bert K (LAA); Stevens, Gary L (LAA); Stoltze, Bill (LAA); 'Therriault, Gene (LAA)'; Thomas, Bill (LAA); Thomas, Joe (LAA); Tuck, Chris; Wagoner, Tom (LAA); Wielechowski, Bill (LAA); Wilson, Peggy A (LAA)
Subject: Public Notice, Additional Information and Proposed Regulation dealing with Commingling of Production
Attachments: Commingling of Production Proposed Regulation.pdf

The Alaska Oil and Gas Conservation Commission proposes to add language to 20 AAC 25.215 to explicitly include commingling in injection wells.

Jody J. Colombie
Special Assistant
Alaska Oil and Gas Conservation Commission
333 West 7th Avenue, Suite 100
Anchorage, AK 99501
(907)793-1221 (phone)
(907)276-7542 (fax)

Colombie, Jody J (DOA)

From: Colombie, Jody J (DOA)
Sent: Wednesday, January 27, 2010 10:05 AM
To: Tammie Wilson
Subject: FW: Public Notice, Additional Information and Proposed Regulation dealing with Commingling of Production
Attachments: Commingling of Production Proposed Regulation.pdf

From: Colombie, Jody J (DOA)
Sent: Tuesday, January 26, 2010 2:23 PM
To: resregs@legis.state.ak.us; (foms2@mtaonline.net); (michael.j.nelson@conocophillips.com); (Von.L.Hutchins@conocophillips.com); alaska@petrocalc.com; Anna Raff; Barbara F Fullmer; bbritch; Becky Bohrer; Bill Walker; Bowen Roberts; Brad McKim; Brady, Jerry L; Brandon Gagnon; Brandow, Cande (ASRC Energy Services); Brian Gillespie; Brian Havelock; Bruce Webb; carol smyth; caunderwood; Charles O'Donnell; Chris Gay; Cliff Posey; Crandall, Krissell; Dan Bross; dapa; Daryl J. Kleppin; David Boelens; David House; David Steingreaber; 'ddonkel@cfl.rr.com'; Deborah J. Jones; doug_schultze; Elowe, Kristin; Evan Harness; eyancy; Francis S. Sommer; Fred Steece; Garland Robinson; Gary Laughlin; Gary Rogers; Gary Schultz; ghammons; Gordon Pospisil; Gorney, David L.; Gregg Nady; gspfoff; Hank Alford; Harry Engel; Jdarlington (jarlington@gmail.com); Jeff Jones; Jeffery B. Jones (jeff.jones@alaska.gov); Jerry McCutcheon; Jim White; Jim Winegarner; Joe Nicks; John Garing; John S. Haworth; John Spain; John Tower; John W Katz; Jon Goltz; Joseph Darrigo; Julie Houle; Kari Moriarty; Kaynell Zeman; Keith Wiles; Laura Silliphant; Marilyn Crockett; Mark Dalton; Mark Hanley (mark.hanley@anadarko.com); Mark Kovac; Mark P. Worcester; Marquerite kremer; Michael Jacobs; Mike Bill; Mike Mason; Mikel Schultz; Mindy Lewis; MJ Loveland; mjnelson; mkm7200; nelson; Nick W. Glover; NSK Problem Well Supv; Patty Alfaro; Paul Decker (paul.decker@alaska.gov); PORHOLA, STAN T; Rader, Matthew W (DNR); Raj Nanvaan; Randall Kanady; Randy L. Skillern; Rob McWhorter; rob.g.dragnich@exxonmobil.com; Robert A. Province (raprovince@marathonoil.com); Robert Campbell; Roberts, Susan M.; Rudy Brueggeman; Scott Cranswick; Shannon Donnelly; Sharmaine Copeland; Shellenbaum, Diane P (DNR); Slemons, Jonne D (DNR); Sondra Stewman; Steve Lambert; Steve Moothart; Steven R. Rossberg; Suzanne Gibson; tablerk; Tamera Sheffield; Taylor, Cammy O (DNR); Ted Rockwell; Temple Davidson; Teresa Imm; Terrie Hubble; Thor Cutler; Todd Durkee; Tony Hopfinger; trmjr1; Walter Featherly; Williamson, Mary J (DNR); Winslow, Paul M; 'Aaron Gluzman'; 'Dale Hoffman'; Frédéric Grenier; 'Gary Orr'; Jerome Eggemeyer; 'Joe Longo'; 'Lamont Frazer'; Marc Kuck; 'Mary Aschoff'; Maurizio Grandi; P Bates; Richard Garrard; 'Sandra Lemke'; 'Scott Nash'; 'Tiffany Stebbins'; 'Wayne Wooster'; 'Willem Vollenbrock'; 'William Van Dyke'; Woolf, Wendy C (DNR); Aubert, Winton G (DOA); Ballantine, Tab A (LAW); Brooks, Phoebe; Crisp, John H (DOA); Darlene Ramirez; Davies, Stephen F (DOA); Foerster, Catherine P (DOA); Grimaldi, Louis R (DOA); Johnson, Elaine M (DOA); Jones, Jeffery B (DOA); Laasch, Linda K (DOA); Mahnken, Christine R (DOA); Maunder, Thomas E (DOA); McIver, Bren (DOA); McMains, Stephen E (DOA); Noble, Robert C (DOA); Norman, John K (DOA); Okland, Howard D (DOA); Paladijczuk, Tracie L (DOA); Pasqual, Maria (DOA); Regg, James B (DOA); Roby, David S (DOA); Saltmarsh, Arthur C (DOA); Scheve, Charles M (DOA); Schwartz, Guy L (DOA); Seamount, Dan T (DOA); Austerman, Alan; Buch, Bob (LAA); Bunde, Con (LAA); Cathy Munoz (Representative_Cathy_Engstrom_Munoz@legis.state.ak.us); Chenault, Mike (LAA); Cissna, Sharon (LAA); Coghill, John (LAA); Crawford, Harry (LAA); Dahlstrom, Nancy (LAA); Davis, Bettye J (LAA); Doogan, Mike (LAA); Dyson, Fred (LAA); Edgmon, Bryce E (LAA); Egan, Dennis W (LAA); Ellis, Johnny (LAA); Fairclough, Anna (LAA); 'Foster, Richard'; French, Hollis (LAA); Gara, Les (LAA); Gardner, Berta (LAA); Gatto, Carl (LAA); Gruenberg, Max F (LAA); Guttenberg, David (LAA); Harris, John (LAA); Hawker, Mike (LAA); Herron, Bob; Hoffman, Lyman F (LAA); Holmes, Lindsey (LAA); Huggins, Charlie (LAA); Johansen, Kyle B (LAA); Johnson, Craig W (LAA); Joule, Reggie (LAA); Kawasaki, Scott Jw (LAA); Keller, Wes (LAA); Kelly, Mike (LAA); Kerttula, Beth (LAA); kevin meyer; Kookesh, Albert (LAA); Lynn, Bob (LAA); McGuire, Lesil L (LAA); Menard, Linda K; Millett, Charisse; Neuman, Mark A (LAA); Olson, Donny (LAA); Olson, Kurt E (LAA); Paskvan, Joe; Petersen, Pete; Ramras, Jay B (LAA); Salmon, Woodie W (LAA); Seaton, Paul (LAA); Stedman, Bert K (LAA); Stevens, Gary L (LAA); Stoltze, Bill (LAA); 'Therriault, Gene (LAA)'; Thomas, Bill (LAA); Thomas, Joe (LAA); Tuck, Chris; Wagoner, Tom (LAA); Wielechowski, Bill (LAA); Wilson, Peggy A (LAA)
Subject: Public Notice, Additional Information and Proposed Regulation dealing with Commingling of Production

The Alaska Oil and Gas Conservation Commission proposes to add language to 20 AAC 25.215 to explicitly include commingling in injection wells.

Jody J. Colombie
Special Assistant
Alaska Oil and Gas Conservation Commission
333 West 7th Avenue, Suite 100
Anchorage, AK 99501
(907)793-1221 (phone)
(907)276-7542 (fax)

Mary Jones
XTO Energy, Inc.
Cartography
810 Houston Street, Ste 2000
Ft. Worth, TX 76102-6298

David McCaleb
IHS Energy Group
GEPS
5333 Westheimer, Ste 100
Houston, TX 77056

Cindi Walker
Tesoro Refining and Marketing Co.
Supply & Distribution
300 Concord Plaza Drive
San Antonio, TX 78216

George Vaught, Jr.
PO Box 13557
Denver, CO 80201-3557

Jerry Hodgden
Hodgden Oil Company
408 18th Street
Golden, CO 80401-2433

Richard Neahring
NRG Associates
President
PO Box 1655
Colorado Springs, CO 80901

Mark Wedman
Halliburton
6900 Arctic Blvd.
Anchorage, AK 99502

Schlumberger
Drilling and Measurements
2525 Gambell Street #400
Anchorage, AK 99503

Ciri
Land Department
PO Box 93330
Anchorage, AK 99503

Baker Oil Tools
4730 Business Park Blvd., #44
Anchorage, AK 99503

Ivan Gillian
9649 Musket Bell Cr.#5
Anchorage, AK 99507

Jill Schneider
US Geological Survey
4200 University Dr.
Anchorage, AK 99508

Gordon Severson
3201 Westmar Cr.
Anchorage, AK 99508-4336

Jack Hakkila
PO Box 190083
Anchorage, AK 99519

Darwin Waldsmith
PO Box 39309
Ninilchick, AK 99639

James Gibbs
PO Box 1597
Soldotna, AK 99669

Kenai National Wildlife Refuge
Refuge Manager
PO Box 2139
Soldotna, AK 99669-2139

Penny Vadla
399 West Riverview Avenue
Soldotna, AK 99669-7714

Richard Wagner
PO Box 60868
Fairbanks, AK 99706

Cliff Burglin
PO Box 70131
Fairbanks, AK 99707

Bernie Karl
K&K Recycling Inc.
PO Box 58055
Fairbanks, AK 99711

North Slope Borough
PO Box 69
Barrow, AK 99723

Mailed
1/27/10

#5

Alaska Oil and Gas Association

AOGA

121 W. Fireweed Lane, Suite 207
Anchorage, Alaska 99503-2035
Phone: (907)272-1481 Fax: (907)279-8114
Email: moriarty@aoga.org
Kara Moriarty, Deputy Director

March 30, 2010

Commissioner Dan Seamount
Alaska Oil & Gas Conservation Commission
333 W. 7th Avenue, Suite 100
Anchorage, AK 99501

Re: Proposed Changes to 20 AAC 25.215 – Commingling of Production & Injection & Proposed Changes to 20 AAC 25.265 – Well Safety Valve System Requirements

Dear Commissioner Seamount:

The 14 members of the Alaska Oil & Gas Association (AOGA) account for the majority of oil and gas exploration, development, production, transportation, refining and marketing activities in the state. We appreciate the opportunity to provide further comment on the Alaska Oil and Gas Conservation Commission (AOGCC) proposed regulation changes to 20 AAC 25.215, Commingling of Production and Injection and 20 AAC 25.265, Well Safety Valve System Regulations.

20 AAC 25.215, Commingling of Production and Injection

We appreciate the additional time to review the revised regulations that were distributed at the March 18, 2010 public hearing. AOGA does not have any further comment as the version presented in the hearing by Mr. Dave Roby adequately addresses our major concerns.

20 AAC 25.265, Well Safety Valve System Regulations – SVS Testing [Section (i)]

During the March 18, 2010 hearing, the AOGCC requested AOGA to provide more information and clarification regarding our suggested language in section (i) of the current draft [which was section (h) in the AOGA March 8, 2010 redline, page 5] regarding safety valve system (SVS) testing and the time required to reach stabilized pressure. Based on comments during the hearing, it appeared the AOGCC would rather have a set timeframe required for testing a well after it is brought on line.

AOGA's comment and intent in adding the additional language on stabilized production was to clarify that a SVS should be tested after a well reaches thermal stabilization. This clarification is consistent with current practice to allow a well to stabilize before it is tested. The current practice is also prescribed in the guiding document "Safety Valve System Guidelines, AOGCC Petroleum Inspection Group, Revised 08/12/98 (item D)".

We believe that most wells will stabilize thermally within 5 days of bringing the well on line, and that the performance test, as prescribed in subsections 1, 2, 4, and 5, should occur within 48 hours after the stabilization has occurred. If a specific timeframe requirement is desired, the references to reaching stabilization in our redline draft should be changed to read " ... within 48 hours of reaching stabilized production or injection, not to exceed 7 days, ...".

As a possible alternative, AOGA suggests the following language to reflect our intent:

"(h) ~~(i)~~ SVS testing is required; wells injecting water are exempt. SVS testing consists of function and performance tests. A function test is defined in 20 AAC 25.990(29). A performance test includes a function pressure test of the system's valves as defined in 20 AAC 25.990(28), and a function test of the mechanical or electrical actuating device. The SVS must be tested within 48 hours after the well reaches a thermal stabilization, not to exceed 7 days, using a calibrated pressure gauge of suitable range and accuracy, as outlined below:

If this approach is adopted, the specific timeframe references in subsections 1, 2, 4, and 5 should be deleted.

20 AAC 25.265, Well Safety Valve System Regulations – Unassisted Flow of Hydrocarbons [Section (m)]

To answer questions voiced during the hearing, AOGA would like to provide additional clarification for our recommended language that would add a new subsection under section (m) [which is section (l) in AOGA's March 8, 2010 redline, page 9], which reads:

"(3) Upon notice to the Commission of an upcoming no-flow test, a well may be produced without an SSSV for up to 14 days to reach a stabilized condition prior to the test. "

Some wells will not likely be capable of unassisted flow of hydrocarbons to the surface when brought on line. Other wells may become incapable of unassisted flow of hydrocarbons after only a short production period. Some of these wells do not currently have, and are not currently required to have, a SSSV. However, a number of these wells are in areas where a SSSV would soon be required under the proposed regulations. AOGA proposed the additional language above to avoid having to equip a well anticipated to pass a no-flow test with a SSSV for only a short period before performing the test.

As noted, in our suggested language, industry would notify the AOGCC prior to the 14 day period.

"Legacy" Guiding Documents

During the March 18, 2010 AOGCC hearing, Mr. Jim Regg provided testimony regarding the AOGCC's plan for consolidation of "legacy" guidance documents, and also for conservation orders which contain references to safety valve systems. AOGA would respectfully request for industry to be part of the process of developing the consolidated guidance document to insure current practices are understood and maintained.

Costs to Implement Proposed Regulations

As stated previously, AOGA supports and strongly believes in the fundamental premise that wells should be designed, constructed and operated in a manner that protects the public, the resource and our workforce. However, we believe that the anticipated benefits of the proposed regulations must be balanced against the potential for increased safety risks and the impact that costs of implementing these new requirements will have on the economic viability of current and future development. For example, applying the new SVS regulations to some low production wells may not actually reduce risk, but instead may have the unintended economic consequence of increasing costs to the extent that the well is shut-in and overall recovery is reduced.

During AOGA's oral testimony at the March 18, 2010 AOGCC hearing, we provided a few examples of the potential financial costs of complying with the proposed regulations. Industry was asked to provide additional information on the cost of the proposed regulations. As a trade association, AOGA can only provide a broad estimate of costs to its members, which range from tens of millions for initial compliance with the new regulations and additional tens of millions for increased operating and maintenance costs over a 20 year period. These costs are based on the proposed regulations discussed during the hearing, assuming they will apply as written to all fields. The costs do not include production impacts due to increased downtime resulting from the new regulations. We understand that the application of any waivers, variances, provisions in conservation orders or changes to the proposed regulations may reduce the impacts and costs to industry. For specific cost analysis, we recommend the AOGCC speak directly to our member companies.

Again, thank you for the opportunity to comment upon these proposed regulations. If you have any questions, please contact me or Harry Engel, chairman of our AOGCC task group, at 564-4194.

Sincerely,

Kara Moriarty

KARA MORIARTY
Deputy Director

Attachment

Cc: Commissioner John Norman
Commissioner Cathy Foerster

Alaska Oil and Gas Association

AOGA

121 W. Fireweed Lane, Suite 207
Anchorage, Alaska 99503-2035
Phone: (907)272-1481 Fax: (907)279-8114
Email: moriarty@aoga.org
Kara Moriarty, Deputy Director

March 8, 2010

Commissioner Dan Seamount
Alaska Oil & Gas Conservation Commission
333 W. 7^{th} Avenue, Suite 100
Anchorage, AK 99501

Re: Proposed Changes to 20 AAC 25.215 – Commingling of Production & Injection

Dear Commissioner Seamount:

The 14 members of the Alaska Oil & Gas Association (AOGA) account for the majority of oil and gas exploration, development, production, transportation, refining and marketing activities in the state. We appreciate the opportunity to comment on the proposed regulation changes to 20 AAC 25.215, Commingling of Production and Injection.

AOGA understands and supports the intent of the regulations regarding injection into two or more pools through the same wellbore. The term "commingling" is typically used to describe the process of *producing* fluids from multiple pools through a single wellbore or combining produced fluids from multiple pools after the fluids have been brought to the surface. The use of the term "commingling" when referring to *injection* of substances is confusing because this is not in the context in which that term has typically been used. We have provided some suggested changes to the proposed regulations for your consideration which we believe meet the intent of the proposed regulations. We believe our suggestions may more accurately describe the process for injection into multiple pools through the same wellbore.

Please consider this communication and the attached redline version as part of the public record associated with this subject. Again, thank you for the opportunity to comment upon these proposed regulations. If you have any questions, please contact me or Harry Engel, chairman of our AOGCC task group, at 564-4194.

Sincerely,

Kara Moriarty

KARA MORIARTY
Deputy Director

Attachment

Cc: Commissioner John Norman
Commissioner Cathy Foerster

AOGA Suggestion

20 AAC 25.215 is amended to read:

20 AAC 25.215 Commingling of Production <u>and Injection into two or more pools</u>. (a) On the surface, the production from one pool may not be commingled with that from another pool except if the quantities from each pool are determined by monthly well tests or by another method of determining pool production approved by the commission.

(b) Commingling of production **~~or injection~~** within the same wellbore from two or more pools is not permitted unless, after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission

(1) finds that waste will not occur, and that production **~~or injection~~** from separate pools can be properly allocated; and

(2) issues an order providing for commingling for wells completed from these pools within the field.

<u>(c) Injection into two or more pools within the same wellbore is not permitted unless the quantities of injection into each pool can be determined by a method approved by the commission.</u>

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am 11/7/99, Register 152; am ___/___/____, Register, ____)
Authority: AS 31.05.030 AS 31.05.095

#4

ALASKA OIL AND GAS CONSERVATION COMMISSION

Before Commissioners: Daniel T. Seamount, Chair
Cathy Foerster
John K. Norman

In the Matter of the Proposed Amendments to 20 AAC 25.215 Regarding Commingling of Production and 20 AAC 25.265 Regarding Well Safety Valve System Regulations.)

ALASKA OIL and GAS CONSERVATION COMMISSION
Anchorage, Alaska

March 18, 2010
9:00 o'clock a.m.

VOLUME I
PUBLIC HEARING

BEFORE: Daniel T. Seamount, Chair
Cathy Foerster, Commissioner
John K. Norman, Commissioner

TABLE OF CONTENTS

PROCEEDINGS

(On record - 9:02 a.m.)

CHAIR SEAMOUNT: On the record. I'd like to call this hearing to order. Today is March 18, 2010. The time is 9:02 a.m. We're located at 333 West Seventh Avenue, Suite 100, Anchorage, Alaska. Those are the offices of the Alaska Oil & Gas Conservation Commission.

I'll start by introducing the bench up here. To my left is Commissioner Cathy Foerster, the Engineering Commissioner, to my right is Commissioner John Norman who holds the Public seat and I'm Dan Seamount the Chair and the Geological Commissioner.

R & R Court Reporting will be recording the proceedings. You can get a copy of the transcript from R & R Court Reporting.

I'd like to remind anyone that's testifying to speak into the microphones so that persons in the rear of the room can hear and so the court reporter can get a clear recording.

This is -- we've got a full house today. In the past we've had hearings where nobody's showed up. So we appreciate everybody's attendance.

Looks like from the sign-in sheet that there's 10 people wanting to testify so far. We'll make opportunity for others if they're interested. And I'd like to remind you that this hearing is covering very specific topics and that is changes, modifications in regulations. And we ask anybody testifying to please keep to the subject because with all these people testifying this could take a lot of time. And time is very valuable to all you, I'm sure.

This hearing is being held in accordance with AS 44.62 and 20 AAC 25.540 of the Alaska Administrative Code. Those are regulations governing public hearings. The hearing will be recorded.

Anyone with questions, if you have a question what you need to do is write out your question, who it's to, put your name on it and hand it to one of our representatives. And I don't know who's our representative in here. Oh, there she is, Ms. Jody Colombie in the back there. Raise your hand. If you have questions, there she is. Just pass it to her.

Okay. Let's see. We have two items today on the agenda. The first is that the AOGCC proposes to add language to 20 AAC 25.215 that will explicitly include commingling of injected fluids. The notice of that hearing was published in the Anchorage Daily News on January 27th, 2010 and it's also posted on the State of Alaska online notices website as well as AOGCC's own website. We received one comment from AOGA on March 8th, 2010.

The second item we'll be discussing is that we are propose -- the AOGCC proposes that well safety valve system requirements in 20 AAC 25.265 will be repealed and readopted and this will incorporate changes that reflect technology advances and safety system design and operation as well as to broaden the scope of applicability. The notice of that hearing was published in the Anchorage Daily News on January 19th, 2010 and it also as well has been posted on the State of Alaska online notices website and well as AOGCC's own website. We received four comments between the period of March 3rd and March 8th and those comments were from Aurora Gas, North Slope Borough, Alaska Oil & Gas Association and ConocoPhillips Alaska.

One thing to mention is the law requires us to consider all factual, substantial and other relevant matter presented to it before adopting, amending or appealing regulations. And one point to make is that the agency is going to pay special attention to the cost to private persons of the proposed regulatory action.

Okay. With that, do you have any comments, Commissioner Foerster?

COMMISSIONER FOERSTER: Not at this time.

CHAIR SEAMOUNT: Do you, Commissioner Norman?

COMMISSIONER NORMAN: No.

CHAIR SEAMOUNT: Okay. Well, let's start with the first item and that is we'll start with testimony and comments on 20 AAC 25.215 concerning commingling of production and injection. And we'll start with David Roby who is one of our Reservoir

Engineers for the Alaska Oil and Gas Conservation Commission.

So please state your name and proceed.

MR. ROBY: My name is David Roby, R-o-b-y. The Commission proposes to amend the regulations contained in 20 AAC 25.215 so that wells used for injection into two or more pools will be given the same level of scrutiny as wells used for commingling of production currently receive.

The regulation currently requires the Commission to provide opportunity for a hearing and to issue an order that finds waste will not occur and production can be properly allocated prior to allowing commingling of production from two or more pools in a wellbore. We have similar concerns for a well that would be used for injection into two or more pools.

After publishing notice of our intent to amend the regulation and our proposed new language, we received a comment and suggested rewording from AOGA. They suggested retitling this section to 20 AAC 25.215, Commingling of Production and Injection into Two or More Pools. They also proposed leaving Part (b) unchanged, instead of implementing the minor changes we had proposed for this part and adding a new section that would read Subpart (c), injection into two or more pools within the same wellbore is not permitted unless the quantities and injection into each pool can be determined by a method approved by the Commission.

While the proposed changes do significantly clarify what we initially were referring to as commingled injection, it does not fully address why we want to amend the regulation. As written their proposed language would only require the Commission to approve an allocation methodology prior to authorizing injection into two or more pools from a single wellbore. While proper allocation is important, it is not our only concern. We are also concerned that the activity will not cause waste and/or damage to either of the pools. For example, oftentimes pools have different fluids that are approved for injection to enhance recovery and it may be inappropriate to inject a type of fluid approved for one pool into another pool. It is possible if the injected fluid is incompatible with the fluid in the reservoir or the reservoir itself it may cause serious, irreparable harm to recovery from that pool. Accordingly, the Commission must not only determine that the injection fluid can be properly allocated between the pools, but must also ensure that resources will not be wasted due to inappropriate injection activities.

As such I propose that we adopt the suggested changes that AOGA submitted, but modify Part (c) to read Subpart (c), injection into two or more pools within the same wellbore is not permitted unless after request, notice and opportunity for public hearing in conformance with 20 AAC 25.540 the Commission one, finds that the proposed injection activity will not result in waste or damage to a pool and that injection volumes can be properly allocated and two, issues an order providing for injection into wellbores completed to allow simultaneous injection into two or more pools.

And I have copies of the -- how the amended regulation would read that I've already provided to the Commissioners and have a few for the audience also.

And that concludes my testimony on this matter.

CHAIR SEAMOUNT: Thank you, Mr. Roby. Commissioner Foerster, do you have any comments, questions?

COMMISSIONER FOERSTER: Thank you, Mr. Roby, and thank you AOGA for your suggestions. And I'm hoping that someone from AOGA will address whether or not the proposed changes are satisfactory. That was my only comment.

CHAIR SEAMOUNT: Would you like them to address the changes now or we have.....

MS. OLSON: I had a question.

CHAIR SEAMOUNT: Excuse me. You have a question?

MS. OLSON: Yes, I.....

CHAIR SEAMOUNT: Your questions you write out and you give to -- well, just one second, Ms. Olson. Commissioner Norman?

COMMISSIONER NORMAN: No, I have no comment and if AOGA is going to testify then perhaps AOGA when they testify could respond to Commissioner Foerster's.....

COMMISSIONER FOERSTER: And if they're not planning to testify -- if they're prepared to give me a comment that's great, if not we'd appreciate it with, you know, in some reasonable amount of time.

CHAIR SEAMOUNT: Okay.

COMMISSIONER FOERSTER: Thank you, Mr. Roby.

CHAIR SEAMOUNT: So, Ms. Moriarty, do you want to do it now or later?

MS. MORIARTY: I'll just do it now.

CHAIR SEAMOUNT: Okay. And we'll get to you in just a minute.

MS. MORIARTY: Good morning, Commission. For the record my name is Kara Moriarty and I'm the Deputy Director for the Alaska Oil & Gas Association.

We do appreciate the opportunity to review the revised suggested language, we always appreciate the Commission taking our suggestions into consideration. Since this is the first time we've seen this we would appreciate, you know, a little bit of time to get back to you reasonably within a week if that's fine so that our full committee can digest the suggestions, if that would be all right.

CHAIR SEAMOUNT: Do we need to rule on that, give them 10 days?

COMMISSIONER NORMAN: I think it would be advisable to set some time, leave the record open in case they want to submit further comments, but that then would apply to everyone during that period can.....

CHAIR SEAMOUNT: So we can leave the record open for 10 days.

(Off record comments - calendar)

CHAIR SEAMOUNT: The end of business the 30th.

MS. MORIARTY: Thank you, Commissioner.

CHAIR SEAMOUNT: Thank you, Ms. Moriarty.

Okay. Ms. Olson, did you have a procedural question or a technical question?

MS. OLSON: A technical question.

COMMISSIONER FOERSTER: Which she needs to write and give it to.....

CHAIR SEAMOUNT: For -- oh, do you have -- you have a statement to make?

MS. OLSON: Well, I just have a question. I don't know what it is.

CHAIR SEAMOUNT: You don't know what is?

MS. OLSON: I don't know what the -- I'm sorry, I'm not as knowledgeable as you. I don't know what waste is.....

CHAIR SEAMOUNT: Okay.

MS. OLSON: .....what it refers to.

COMMISSIONER FOERSTER: This isn't the place for that.

CHAIR SEAMOUNT: Okay. What you need to do is -- well.....

COMMISSIONER FOERSTER: This isn't the place for that.

CHAIR SEAMOUNT: Yeah. We don't have the time to discuss it, but our Staff would be glad to discuss it with you afterwards.

MS. OLSON: Well, it's being presented and so that's why I -- I'm expected to testify and that's why I thought maybe you could give me a simple -- someone could answer.....

(Whispered conversation)

COMMISSIONER FOERSTER: Mrs. Olson, the purpose of this hearing is not to educate the general public on our terminology that we use. We expect that people coming in to testify have some level of knowledge about what they're going to discuss. So if you are looking to discover what we're talking about so then you can make some testimony, that's totally inappropriate.

MS. OLSON: I just wanted to say I wanted to make sure I stayed on track and so.....

COMMISSIONER FOERSTER: We'll tell you if you get off track.

CHAIR SEAMOUNT: Yeah, we.....

MS. OLSON: Well, that's rather arbitrary.

CHAIR SEAMOUNT: .....can help you on that, but -- okay. Basically waste is spilling oil or spilling gas to the atmosphere.

COMMISSIONER FOERSTER: Or leaving it in the ground.

CHAIR SEAMOUNT: Or leaving it in the ground.

MS. OLSON: Okay. Thank you.

CHAIR SEAMOUNT: Okay. So we will now -- unless either of the Commissioners have any other comments?

COMMISSIONER FOERSTER: No.

CHAIR SEAMOUNT: Okay. We'll open this to testimony from the public concerning commingling of production and injection, the change to the regulation on 20 AAC 25.215. Is there anyone from the public that would wish to testify on this?

Ms. Olson, please approach the bench. And please try to keep your topic to the issues at hand.

MS. OLSON: I'd like to address the Commission by saying, first of all, there's too much diversity. And so when you attempt to restrict my free speech I would have to object because I own my own oil and gas and you're not simply operating as a state agency on leases.

CHAIR SEAMOUNT: Oh, please state your name and -- for the record.

MS. OLSON: For the record my name is Dana L. Olson. I live in Knik, Alaska. I have historical property and I've been in partition. And it is the type of ownership that allows me to own all the oil and gas. And so this is -- comes full bore with your attempts to regulate and attempts to define my developmental rights. And so that's why I'm making an objection.

I wanted to let you know that it was very difficult for me to be here and so that I took the matter very seriously. I don't believe that you have adequately defined wasted, that is too general a thing, it certainly fall under a regulatory standard.

The -- there is no test that I can find that you presented for the public to review for the balancing of interests. And if we were going to take the matter, you know, administratively on appeal then we would want to know what the test was. And I don't feel that you have provided it, I don't feel that the normal agencies that respond to you or associations that respond to you have come up and adequately provided what they consider the balancing test is.

Now I have been interested in USGS subjects and since you raised the issue about USGS, you being an expert, I don't feel that it is inappropriate for me to raise the issue about the polarity and whatnot. I've raised that issue before and I was actually admonished for doing so. And so that kind of makes me feel uncomfortable to come to your meetings when you're an expert in it and I raise the issue and I am admonished.

I have historical water rights, they were argued December 8th, 2009 before the Alaska Supreme Court. And I don't find that your zeal, I guess, to make everyone happy who's got a lease out there is adequate. One of the things that I find very disturbing is the fact that when I am not an expert and I asked to sell my oil and gas to the State, to partner, the Division of Oil & Gas refuses. And.....

CHAIR SEAMOUNT: Well, we have no authority over the

Division of Oil & Gas.

MS. OLSON: .....what I'm trying to say is that while you tried to work within the industry itself, the State itself doesn't work under partnerships. So if we have the capacity to form partnerships and whatnot, we have to have it available for all persons owning oil and gas, we can't just have the ones that are favored by the Commission.

CHAIR SEAMOUNT: Well, I appreciate your comments on that, Ms. Olson, but this Commission has no authority over the rights that you're talking about.

COMMISSIONER FOERSTER: Nor.....

CHAIR SEAMOUNT: You have to go to the Division of Natural Resources at least for that.

COMMISSIONER FOERSTER: Nor does the subject have anything whatsoever to do with the commingling of production.

MS. OLSON: Well, it does because I padded.....

COMMISSIONER FOERSTER: Because you don't understand what commingling of production means.

MS. OLSON: Well, I had an injection case before the Supreme Court and so I had how the court reasoned with me and that's my basis for here is that. Until you come up with your test to see that we're -- your -- you've got a balance, then I would find that you are not doing a regulatory process. You may be doing some type of agreements or whatever.

But one of the things is that you've got to understand that there are biofield productions, there are other types of oil and gas activity and when you own the full mineral -- you own the full estate, we actually have a greater property interest than what you address.

CHAIR SEAMOUNT: And that.....

MS. OLSON: And I want to.....

CHAIR SEAMOUNT: .....again I say we -- that's not under our purview.

MS. OLSON: But I wanted to say that Attorney General Opinion 7 makes it quite clear that a local government ordinances are only administratively, they're not legislative. So if we can't speak to our local government within our Coastal Management Area then it brings to question.....

CHAIR SEAMOUNT: Again that comes under the Department of Natural Resources, Ms. Olson. We appreciate you.....

MS. OLSON: No, I'm talking about the Mat-Su Borough is where I live.

CHAIR SEAMOUNT: Well, then go to the Mat-Su Borough.

MS. OLSON: I.....

CHAIR SEAMOUNT: We appreciate you coming. How did you get in here? I know it took a lot of work to get in here, we appreciate that.

MS. OLSON: I stayed up all night, caught a bus at 5:00 a.m. and am here.

So but I am not happy when I come to your things and I don't know what the legal standards are. And you all talk amongst yourselves as -- and you get Ms. Foerster commenting to me personally about we're not here to educate the public. There is a provision under the Sunshine Act federally.....

CHAIR SEAMOUNT: We are here to educate the public, but not in this hearing.

MS. OLSON: No, what I'm trying to say is.....

CHAIR SEAMOUNT: You're welcome anytime to call our people.

MS. OLSON: I did come in, sir. I did come in prior to the meeting and ask questions.

COMMISSIONER FOERSTER: And I sat down with you and chatted with you for about 20 minutes.

MS. OLSON: Yes. But what I'm trying to say is the Sunshine Act is an Act that I don't think you're following and it's federal law. And so I would ask that the Commission send me a letter how they're complying with it.

Thank you.

CHAIR SEAMOUNT: Okay. Duly noted and we've got you on the record. And we appreciate.....

MS. OLSON: Okay.

CHAIR SEAMOUNT: Thank you very much, Ms. Olson.

Okay. So are there any other comments from the public? Hearing none we will move to the main event as I see it.

And this concerns the AOGCC's proposal regarding well safety valve system requirements in 20 AAC 25.265, which will be -- which we propose to be repealed and readopted to incorporate changes that reflect technology advances in safety system design and operation as well as to broaden the scope of applicability.

Thank you, Ms. Olson, I appreciate that you took so much effort to come in here and see us.

MS. OLSON: Well, I know I'll always be passionate and I expect that.....

CHAIR SEAMOUNT: We appreciate that.

MS. OLSON: Thank you.

CHAIR SEAMOUNT: Okay. So we'll start with the AOGCC's representative, Dr. Winton Aubert.

(Off record comments)

CHAIR SEAMOUNT: Dr. Aubert will provide comments for the AOGCC before we get into the wrestling match.

Please state your name for the record even though I've already stated it.

DR. AUBERT: Thank you. For the record I'm Winton Aubert, Senior Engineer on the Commission Staff.

Today we propose repeal and readoption of Title XX, Chapter 25 of the Alaska Administrative Code, Section 265 currently titled automatic shut-in equipment. If enacted new Section 265 will be more appropriately titled well safety valve systems.

On August 28, 2007 this panel heard testimony regarding the necessity of well safety valve systems. These systems are intended to be automated means of preventing hydrocarbon waste, ensuring safe well operation and limiting environmental impact should a well system failure lead to uncontrolled well flow. In order to accomplish their design purpose, well safety valve systems obviously must be installed, maintained and operated in ways that ensure reliable functioning under all conditions to which the system may be subjected.

The Commission also heard testimony that militates in favor of redrafting Section 265. The current Section 265 is vaguely worded and coverage gaps exist leading to confusion and varying interpretations by industry and Commission Staff. Regulatory gaps have heretofore been filled with unpublished guidance and policy, placing new personnel and operating companies at a disadvantage.

Section 265 was originally intended to be a performance based regulation, but historical practice, lack of industry guidance and years of interpretation have rendered the current regulation ineffective. In addition through enactment of pool rules safety valve system requirements vary, at odds with the Commission's aim for clear and consistent regulations. In short the current Section 265 does little to provide the Commission with a clearly understood and legally defensible regulation capable of underpinning safety assurance through meaningful compliance inspections.

Today's proposed Section 265 has undergone extended technical and legal reviews by Commission Staff, the Alaska Attorney General's Office and industry. Prior to the 2007 hearing the Commission received written comments from ConocoPhillips Alaska, Marathon Oil and the Alaska Oil & Gas Association companies. We have incorporated many of those suggestions in the present proposed Section 265.

Our subject proposal contains significantly embellished requirements relative to the existing Section 265. We now propose requiring safety valve systems on all wells with specific exclusions, safety valve system components and configuration are specified, subsurface safety valve application is now precisely prescribed and operation of related well equipment is tied in. We also now propose timing for backfitting existing wells, subsurface safety valve placement relative to permafrost depth is specific, safety valve system testing and inspection are closely controlled and treatment of failed individual safety valve system components is prescribed. We further codify conditions under which safety valve systems may be defeated and the tagging requirements thereof, detailed criteria for no flow testing are enumerated and establishment of a single point of contact for all safety valve system documentation is compelled. Finally we propose adding to Section 265 an explicit variance and waiver flexibility.

That concludes my prepared remarks. Does the panel have any questions at this time?

(Whispered conversation)

CHAIR SEAMOUNT: Thank you, Dr. Aubert. Commissioner Foerster.

COMMISSIONER FOERSTER: I didn't know some of the big words you used, but I'll ask you to explain them later.

CHAIR SEAMOUNT: Any comment?

COMMISSIONER FOERSTER: That's it.

CHAIR SEAMOUNT: Commissioner Norman.

COMMISSIONER NORMAN: No. And I -- thank you, Dr. Aubert, and I assume you will remain through the hearing so that if we have to recall you you'll be available. Thank you.

CHAIR SEAMOUNT: Okay.

COMMISSIONER FOERSTER: Oh, I do have a question for Dr. Aubert.

Dr. Aubert, could you describe the process by which we received industry's input into these regulations?

DR. AUBERT: A number of formal work sessions were held with industry personnel which led to the first version of our proposed new Section 265. There have been many informal discussions dating back several years also between Commission Staff and industry personnel leading to what we've proposed today. As I mentioned, industry commented in writing prior to the 2007 hearing and this current version has incorporated a number of those suggestions.

COMMISSIONER FOERSTER: Okay. Do you feel that the technical Staff making the proposed regulation changes made a fair attempt to try to honor a wide diversity of requests wherever you could?

DR. AUBERT: In my opinion, yes.

COMMISSIONER FOERSTER: Okay. Okay. And are there still some major differences in opinion?

DR. AUBERT: There are some points of contention between our proposal and industry's position. And I'm sure those are going to be covered in great detail in subsequent testimony.

COMMISSIONER FOERSTER: Okay. Thank you.

CHAIR SEAMOUNT: Thank you, Dr. Aubert. Is there anyone else from the Commission that's going to testify?

COMMISSIONER FOERSTER: I've asked Mr. Regg to be available to testify at the end of industry's comments.....

CHAIR SEAMOUNT: Okay.

COMMISSIONER FOERSTER: .....so that -- because I think that some of his comments -- some of their comments he may be able to add to.

CHAIR SEAMOUNT: Okay. Okay. So now -- we'll now open it to public testimony. I guess we'll go in order of first come, first serve. Is that okay with the two Commissioners?

COMMISSIONER FOERSTER: Fine with me.

CHAIR SEAMOUNT: Okay. The first one is Ms. Moriarty from AOGA. Could you please come forward and state your name for the record. Do you wish to be sworn or do both of you wish to be sworn? We should swear them in, right? Okay. Both of you please raise your right hand.

(Oath administered)

MS. MORIARTY: Yes.

MR. ENGEL: Yes.

CHAIR SEAMOUNT: Okay. Thank you. And AOGA may start their testimony by giving me your name.

KARA MORIARTY

called as a witness on behalf of AOGA, testified as follows on:

DIRECT EXAMINATION

MS. MORIARTY: Good morning, once again Commissioner Seamount, Norman and Foerster. For the record my name is Kara Moriarty, I'm the Deputy Director of the Alaska Oil & Gas Association. As you know we represent the majority of the oil and gas activities and companies here in the state, we currently have 14 members.

We -- as Dr. Aubert mentioned, AOGA was very involved back in 2006 during the informal work sessions that we had or the formal work sessions that we had that led to the 2007 hearing where we did participate and gave substantial comments and provided various documents. And I think at that time we even had a detailed power point presentation and we actually brought in a model and things to demonstrate. Since that time our member companies have been in informal conversation with AOGCC Staff and we welcomed once again the opportunity to provide comment.

With me today is Harry Engel with BP, he chairs our AOGCC task group and he'll talk a little bit more about our continued concerns with the regulations and the proposed redline with suggestions for you and your Staff to consider. This round of -- in the last six weeks or so since we've been meeting on the revised draft, we've had very broad participation of our membership from Cook Inlet and North Slope companies, big and small. So I just -- Harry will go through that in more detail as well of the companies that actively participated, but we feel very comfortable that this represents Alaska's industry's viewpoint on your proposed regulation.

And with that I'm happy to entertain any other questions, but I'll turn it over to Harry to get into the details.

CHAIR SEAMOUNT: Commissioner Foerster.

COMMISSIONER FOERSTER: So am I correct in hearing that Harry will be speaking as a representative of all the AOGA companies and not simply as a representative of his own company?

MS. MORIARTY: That is correct.

COMMISSIONER FOERSTER: And.....

MS. MORIARTY: He represents.....

COMMISSIONER FOERSTER: Okay.

MS. MORIARTY: .....the AOGA task group today.

COMMISSIONER FOERSTER: And he.....

MS. MORIARTY: We have several other members in the audience today.

COMMISSIONER FOERSTER: Okay. So if I ask Mr. Engel a question that is more appropriate for Marathon he'll use a lifeline if he needs to?

MS. MORIARTY: He could. He could.

COMMISSIONER FOERSTER: Okay.

MS. MORIARTY: He has a couple lifelines.....

COMMISSIONER FOERSTER: Okay.

MS. MORIARTY: .....in the audience, yes.

COMMISSIONER FOERSTER: Okay.

MS. MORIARTY: We do have representatives from Chevron and Marathon and a few other today.

COMMISSIONER FOERSTER: Okay. Thanks.

CHAIR SEAMOUNT: Commissioner Norman, do you have any comments before we get on to Mr. Engel?

COMMISSIONER NORMAN: No comments.

CHAIR SEAMOUNT: Okay.

HARRY ENGEL

previously sworn, called as a witness on behalf of AOGA, testified as follows on:

DIRECT EXAMINATION

CHAIR SEAMOUNT: Mr. Engel, would you like to be considered as an expert witness?

MR. ENGEL: Yes, Commissioner Seamount.

CHAIR SEAMOUNT: Okay. Then please state the subject and what your qualifications are.

MR. ENGEL: Drilling production operations.

CHAIR SEAMOUNT: Okay. And your qualifications?

MR. ENGEL: I have.....

CHAIR SEAMOUNT: I know this is getting tiresome because we've.....

MR. ENGEL: We've been through it a few times.

CHAIR SEAMOUNT: .....you've been an expert witness a few times. I know in the state of Utah once you're an expert witness in the state you're always an expert witness. We ought to work on making that change for Alaska. But please.....

MR. ENGEL: Yeah, I understand.

CHAIR SEAMOUNT: .....please go ad nauseam.

COMMISSIONER FOERSTER: He likes talking about himself.

MR. ENGEL: Currently today I am representing AOGA as the Chairman of the AOGCC task group. In my real job I am engineering team leader in BP's Drilling and Wells organization and I manage our Integrity Management program for the entire Alaska operations for BP spanning Milne Point through Badami.

I hold two undergraduate engineering degrees, I have over 29 years of experience in the oil and gas industry mainly involved with drilling and well activities. My assignments have included drilling engineering positions, well site leader roles and various health, safety and environmental positions. The majority of my experience has been in most of the operating areas in Alaska and I have worked in the Rocky Mountain in the U.S. and I've had several international assignments with BP and ARCO.

CHAIR SEAMOUNT: Commissioner Norman, do you have any objection to Mr. Engel being considered an expert witness?

COMMISSIONER NORMAN: Thank you, Mr. Chairman. Certainly no objection, Mr. Engel's well known to the Commission.

I just make a statement for the public that sometimes it does get repetitious asking for statements of qualifications, but we are making a public record and if two or three years from now someone wants to go back, lawyers or even if this were to be appealed, a judge, they just read the record of this hearing, they don't know all the times that someone has been here before. And so that's why even though it's a bit repetitious it is necessary to go through this so that we have a good, complete, stand alone record at the end of the hearing.

But thank you, Mr. Engel. And I have no other -- certainly no questions for Mr. Engel.

CHAIR SEAMOUNT: Thank you, Commissioner Norman. Commissioner Foerster, do you have any objections or comments?

COMMISSIONER FOERSTER: I have none.

CHAIR SEAMOUNT: Okay. Mr. Engel, you are again for the twentieth time designated as an expert witness.

MR. ENGEL: Thank you, Commissioner Seamount. This morning I will address AOGA comments that we submitted to the Commission on March 8th, 2010 concerning the proposed regulations regarding safety valve systems. I request that those comments submitted on March 8th be included in the public record concerning this topic. And in addition I would like to request that the Commission also incorporate our comments and testimony of August 20th, 2007 and August 28th, 2007 respectively, be included in the record because they do address this issue we're talking about this morning.

First I'd like to acknowledge the following AOGA member companies who provided some valuable information and input as we develop our comments for the proposed regulations. They include Pioneer, ExxonMobil, ENI, Chevron, Marathon and BP.

I would also like to acknowledge the AOGCC Staff members, Mr. Jim Regg, Dr. Winton Aubert and Mr. Tom Maunder for their efforts to enhance the understanding between the AOGCC and industry with respect to the intent of the proposed regulations.

It's kind of funny in one respect, this morning I feel like Yogi Berra as I flash back to August, 2007 on this hearing. It's deja-vu all over again. Also I feel like Bill Murray in one respect, in the movie Ground Hog Day because back in 2007 I think I was sitting in this seat, exact seat, before the same Commission talking about the same topic.

CHAIR SEAMOUNT: But were you an expert witness?

MR. ENGEL: I believe I was, but I'll let the record reflect that.

And today I'm confident that the work done in the past and the openness of the Commission to consider industry's comments will create a reasonable and clearly understood regulation for industry in Alaska.

AOGA members strongly believe that all oil and gas operations must be designed, constructed and maintained in accordance with sound engineering standards and practices. Our operations must provide a safe work place, protect the environment in which we work and live and reduce overall risk.

The proposed regulations which are about five pages in length are significant when compared to the current half page automatic shut in equipment requirements currently in 20 AAC 25.265. We are unclear to the actual risk benefit, risk reduction and reason for several of the proposed changes. Risk is defined as the product of probability and consequence. It would be helpful if the Commission could provide tangible examples or justification that would support some of the changes in the proposed regulations. In some cases additional risk could result with no incremental protection provided.

It is our understanding that one of the purposes of the proposed regulations is to standardize, streamline and provide clear and consistent requirements across the state to remove confusion association with what I'll refer to as legacy documents related to safety valve systems. Since 2003 with the development of the AOGCC/Alaska Oil & Gas Association safety valve system task force, the Alaska oil and gas industry has embraced the effort to bring clarity to the subject of safety valve systems. During the last hearing on the subject in August, 2007, AOGA members submitted written comments and provided testimony.

A major component of our comments related to AOGCC conservation orders, guidance documents, polices, procedures and legacy letters that address safety valve systems. I have a few examples of these documents. One is a Commission field operations procedure for no flow test dated April 24th, 1992. Another one is AOGCC's policy for SVS failures dated March, 1994. Another one is safety valve system guidelines for the Commission's petroleum inspection group dated August 12th, 1998. There are several letters from the Commission to operators. One for example is dated 11/14/1995 related to the six month test interval and 10 percent failure rates. Another one is dated March 10th, 1997 related to failures due to frozen safety valve systems. There is also AOGCC industry guidance bulletin number 06-04 related to subsurface safety valves. And there's also numerous correspondence to operators regarding testing reporting and failure calculations and also documents related to various SVS policies and guidelines. Most of these documents are not available to operators on the AOGCC webpage.

In addition the proposed regulations do not address such issues as the impact to current AOGCC conservation orders, calculation of pad failure rates or additional testing requirements and potential consequences.

Considering many of these issues raised in the August, 2007 hearing have not been addressed, AOGA members are concerned that this effort will not meet the intended goal of providing clear and consistent regulations across Alaska. Alaska operators need to have clear guidance with respect to these issues to ensure operations are conducted in compliance.

Now I'd like to go through a few of the -- a few of the sections in our comments that we provided in writing on March 8th, 2010. The first area addresses linked safety systems and it's Section 25.265(c)(5). In summary we recommend that this section be deleted. And the reason for that is that it's unclear that there is a significant overall risk reduction with the link system -- a linked safety valve system over independent producing or injection safety valve systems.

Producing wells sharing a common flowline are commonly equipped with independent safety valve systems. In these independent systems a failure in a flowline reflected by a pressure decline is independently sensed by each well's low pressure detection device, actuating the independent safety valve. Facility modifications will be required to link the system to conform to the proposed regulation. These modifications could involve piping or electrical work to run a hydraulic line or electrical connections between the wells, sometimes hundreds of feet apart. This link between the wells will require ongoing inspection and maintenance to ensure reliability. In addition at low temperatures the increased viscosity of the oil used in hydraulic systems will reduce the reliability of the linked system.

For example in Greater Prudhoe Bay there are approximately 100 groups of wells flowing into a common flowline or common flowlines. About half of thee or a minimum of about 100 wells would require the modifications I just mentioned. It is anticipated that it would cost approximately $20,000 per well to link all these wells for a total initial cost of in excess of $2 million. This does not include preventive maintenance or replacement costs. This is a fraction of the twin wells in service in Alaska that would be required to be linked under the proposed regulations. Considering we are not aware of any situation where existing independent safety valve systems have not been effective, the significant incremental costs and questionable risk reduction benefit, we urge the Commission to reconsider the need for this section in the regulation.

The next area I'll address is 25.265(d)(2). And this section identifies onshore well locations within one-eighth of a mile of certain areas that will be required to have fail-safe surface controlled subsurface safety valves.

This section could have significant consequences on current and future exploration and development of Alaska resources, especially in the Cook Inlet marginal gas fields. Cook Inlet fields operated by AOGA members and impacted by this regulation include Cannery Loop which produces about 18 million cubic feet of gas per day and Ninilchik Unit which produces about 50 million cubic feet of gas per day. Wells in these units are equipped with surface safety valves. Many of these wells are A, monobores, making the installation of a subsurface valve complex and expensive and B, they're located in unpopulated areas, even though they still fall within a one mile -- one-eighth of a mile of a public road or the coast.

The next area I'd like to address is Section 265(d)(3) and this relates to production wells equipped electrical submersible pumps or ESPs or capillary strings.

There is no exemption specifically in the proposed regulations to the subsurface safety valve requirement in wells equipped with ESPs or capillary strings. For example, packers are not run in Mile Point producing wells equipped with ESPs based on the prior determination that safety valves were not required per AOGCC Conservation Order 390. Findings in the Conservation Order 390 are still valid for wells equipped with both ESPs and packers. I reference findings four and five in Conservation Order 390. Quote, packers impede the effective operation of ESP wells. Efficient pump operations require venting gas away from the pump to prevent operational difficulties and damage to the pump. Setting packers shallow to allow gas to accumulate in the annulus causes complications in killing the wells prior to well repairs or changing pumps. Approximately 35 ESP change out workovers are performed in the Milne Point Unit each year. And the cost for a workover at Milne Point to change out a pump is approximately $400,000.

The use of subsurface safety valves in wells with ESP and capillary strings will limit the use of some technologies that would otherwise make marginal investments more attractive. For example the use of through-tubing deployed pump systems can significantly reduce the cost of an ESP workover by providing a means of rigless pump change outs by way of slickline or coiled tubing. The cost for a ESP pump change out by way of slickline is approximately $100,000. So you can see there's a significant cost benefit by using the new technology to deploy and retrieve ESPs by way of slickline operations. Through-tubing ESP systems cannot currently be run through standard subsurface safety valve equipment to the drift requirements of the through-tubing components. These pump change outs can be required as often as every two years. When considering production operation costs for a large number of producing wells the savings using new technology can have a significant impact on project economics without increasing risk to safety. Use of these technologies extends field life, enhances recovery and minimizes waste.

We therefore request a specific exemption be placed in these regulations for wells equipped with ESPs or capillary strings.

The next area I'd like to address is Section 265(d)(5) and that's in AOGA's redline version. I want to make a note here that considering our recommendation to move Section (e) into Section (d), the following comments I'll refer to the numbering in our redline version of the proposed regulations just to avoid any confusion on the reference.

MS. MORIARTY: And, Commission, just to clarify on our redline Mr. Engel is currently on page 4.

MR. ENGEL: Okay. Moving along to 265(d)(5). For clarity we suggest this section be moved under Section (d) which addresses subsurface safety valves becoming (d)(5).

We understand the intent of this section is to require subsurface safety valves in dedicated gas injection wells and water-alternating or WAG wells while they are injecting gas. Risk profiles will vary significantly between large volume, high pressure dedicated gas injection wells such as in Prudhoe Bay used for reservoir pressure maintenance and relatively low volume water-alternating-gas wells used for enhanced recovery in other fields in Alaska. The risks with operating and maintaining subsurface valves in low volume, high pressure WAG wells may be greater than any safety benefit from the valves. In these wells the specific injection valve design will not be suitable for both water and injection service. This will require additional intervention operations to pull and replace the injection valve at each WAG cycle change, including times with high pressure gas in the wellbore. Considering this operators may request a waiver that's provided for in these regulations.

The next area I'd like to address is 265(h) which addresses safety valve system testing.

In this section and consistent with current practices we have recommended including language that would allow a well to stabilize, thereby providing adequate time for a safety valve system to thermally stabilize before testing.

The next area I want to address is 265(h)(10) and (11) which also addresses SVS testing.

The American Petroleum Institute recommended practices or RPs 14B and 14H provide specifications for a new or repaired surface and subsurface safety valves that are in service. We have reviewed these RPs and they are currently in effect.

COMMISSIONER FOERSTER: Mr. Engel, I'm confused. Are you talking about our Section (i), you refer to it as Section (h), but are you really talking about our Section (i)?

MR. ENGEL: Yes, I'm referring to Section (h) in our redline, Commissioner Foerster.

COMMISSIONER FOERSTER: Oh, your -- to what you want to become (h), but what is currently carried as (i)?

MR. ENGEL: That's right.

COMMISSIONER FOERSTER: Okay. Gotcha.

MR. ENGEL: Yeah, that's why I made that comment earlier that I -- my references is to our.....

COMMISSIONER FOERSTER: Okay.

MR. ENGEL: .....redline version.

COMMISSIONER FOERSTER: Okay.

MR. ENGEL: Yeah. And you can see your version has got the crossed out.....

COMMISSIONER FOERSTER: Okay.

MR. ENGEL: .....letter.

COMMISSIONER FOERSTER: Okay. So what you're referring to is your adopted.....

MR. ENGEL: (h).

COMMISSIONER FOERSTER: .....tags for these things. Okay.

MR. ENGEL: Yes, do you have that?

COMMISSIONER FOERSTER: I'm with you now.

MR. ENGEL: Okay. Very good. Thank you. So I'll back up a second to make sure we're all on the same page here.

The American Petroleum Institute recommended practices 14B and 14H provide specifications for a new or repaired surface and subsurface safety valves that are in service. We have reviewed the referenced RPs and they are currently in effect. These specifications allow the indicated leak rates that we've had in our -- I put in my written comments. The exact closing time for a subsurface safety valve may be impossible to determine, thus it may be impossible to determine if detectable leakage is occurring in four minutes. In AOGA's redline version operators may choose to use the no detectable leakage criterion or actually calculate or measure the leak rate of a safety valve. Portable gas meters are available and in use to measure gas leak rates. These are similar to household gas meters you have in your own. Liquid leak rates are determined by measuring the flow into a calibrated tank over a period of time to determine what that liquid leak rate would be.

The next area I'd like to move on to is 265(i), that's AOGA version (i), which addresses SVS components that fail performance tests.

The proposed regulations would require a failed SVS component to be immediately repaired or replaced. The phrase immediately be repaired or replaced and performance tested is not well defined. This also applies to Sections (i)(1), (2) and (3). We request at least 12 hours to diagnose the problem and repair or replace the actuating device before requiring the well to be shut in. Additional time is allowed in various conservation orders if the pad is continually manned.

We recommend language changes to reduce confusion and to allow additional time for repair or replacement of valves if the pad is continually manned.

The next area I'll address is 265(i)(4) in AOGA's redline version. And this addresses positive sealing devices used in SVS testing.

Where redundant valves are functional we recommend the positive sealing device be repaired or replaced within 14 days. The positive sealing device used to test a safety valve system is normally the wing valve on the tree. This valve is also the primary well control valve so if the valve fails to seal typically a work request is submitted to repair or replace the valve as soon as possible. However the valve is not the only valve available for testing purposes or for controlling well flow, nor is it part of the safety valve system described in Section (c) above. Replacement of the valve may require more time than seven days to schedule personnel and equipment, to erect scaffolding, drain and purge the flowline and to pressure test the system. Shutting in the well during this time period will cause unnecessary loss of production when the SVS has already been proven functional and effective.

I'll wrap up with a general comment. Considering the magnitude of the proposed regulations, the extensive comments provided by industry and significant potential impact to operators, we recommend that industry have the opportunity to review the final draft of the proposed regulations in a public forum before they are adopted in final form.

Thank you again for the opportunity to provide comments regarding the proposed regulations. I'll be happy to address any questions you may have at this time.

CHAIR SEAMOUNT: Thank you, Mr. Engel. Commissioner Foerster, do you have any questions or comments.

COMMISSIONER FOERSTER: I have quite a few. First thank you for the depth and breadth of your review of our regulations. We really appreciate that. And you -- I'll ask of you the same indulgence you asked of me. I'm going to refer to the regulations according to our numbering for them.....

MR. ENGEL: Very good.

COMMISSIONER FOERSTER: .....instead of yours.

MR. ENGEL: Yeah.

COMMISSIONER FOERSTER: And I'll ask you to be as flexible as I tried to be for you.

On Section (d)(2) of -- I understand your concern about special consideration for marginal wells, but I was wondering couldn't these concerns or wouldn't they be more appropriately addressed in individual conservation orders or waivers.....

MR. ENGEL: I think that would be -- I think that would be.....

COMMISSIONER FOERSTER: .....would that be acceptable?

MR. ENGEL: .....I think that would be acceptable if an operator could address those on a case by case basis or in an order.

COMMISSIONER FOERSTER: Because they're a special case, I'm wondering wouldn't it be -- you know, if we're looking at statewide rules, not make them, you know, deal with specific instances that might better be addressed in a waiver or a CO?

MR. ENGEL: I think that would be appropriate.

COMMISSIONER FOERSTER: Okay. All right. On (e)(2), you don't want the regulations to apply to WAG wells is what I'm hearing.

MR. ENGEL: Well, Commissioner Foerster, what section are you in -- referring to?

COMMISSIONER FOERSTER: I think it's (e)(2).

MR. ENGEL: Just Section (e)?

COMMISSIONER FOERSTER: Yes.

MR. ENGEL: The issue with this topic, Commissioner Foerster, is having a valve that would accommodate water injection and gas injection is very difficult. The parameters of an injection versus a water injection would be -- are difficult to do. So they'd be changing out a valve for water, putting in for gas. And if you have -- for a low volume gas injection well the opening that would be required to allow the well to operate is very small. And that would inhibit -- that could create some problems, for example, well control purposes. So one size doesn't fit all, the profile of these wells are different and the operating parameters would dictate the design for an effective safety valve.

COMMISSIONER FOERSTER: Do you currently have subsurface safety valves in your WAG wells?

MR. ENGEL: Some operators have -- BP, for example, does have downhole valves, it could be an injection valve or it could be a surface controlled safety valve.

COMMISSIONER FOERSTER: So it's having the valves in the wells that you object to, it's not testing them or having them apply to the failure rates, but it's just having the valves themselves in the wells to which you object? I'm trying to make sure I understand what the real -- what your real concern is because, you know, you -- and where the concern -- I hear you say they don't work when they're in wells, but yet I hear you say that some wells have them. So that's a -- I need a better understanding for what you're -- where we're going with this.

MR. ENGEL: Yes, I understand your question. Referring to Section (e) here. The -- to summarize the issue, Commissioner Foerster, I believe the concern is having these valves in WAG wells is going to require some operational -- additional operational intervention to pull and re-run valves when you're on water versus on gas injection. And for well -- for example, comparing a well in Prudhoe gas cap injection, we're injecting very high volumes of gas in very high pressure. That's a different scenario than a WAG well that may be operating at a very low volume of gas. So the risk profile is quite different and we don't believe that the valve would actually add benefit in that situation. So on a case by case basis the evaluation would have to be considered on does a valve in a low productive well really provide you any additional risk reduction for the operation. So it is around the type of well and the type of valve that would have to be required in that well.

COMMISSIONER FOERSTER: Okay. Well, you know, it's possible that I'm not grasping everything you're trying to get me to grasp, but what I'm hearing is that for a lot of your WAG wells you do already have the safety -- subsurface safety valves and that on a case by case basis you determine whether they're appropriate or not and when I hear case by case basis, a lot of them have -- that makes me tend to think that, you know, statewide rules stay broad and case by case basis is dealt by -- is dealt with on a case by case basis.

MR. ENGEL: Yeah. Let me clarify the statement about -- you mentioned that all WAG wells. All WAG wells may not have a valve in.....

COMMISSIONER FOERSTER: He didn't say all wells, some do. He.....

MR. ENGEL: Some do.

COMMISSIONER FOERSTER: Yes.

MR. ENGEL: The point here is that all gas injection wells are not the same, that a dedicated gas injection well is totally different than a well on WAG. So.....

COMMISSIONER FOERSTER: I understand that. We're -- let's talk about WAG wells.

MR. ENGEL: So the concern is around having a valve on these wells that we don't feel it may provide any additional safety for a well that's got a low productivity potential.

COMMISSIONER FOERSTER: And so there ... hose wells that you are currently operating th... subsurface safety valves in them?

BP is the only AOGA member company that operates WAG injectors

MR. ENGEL: When -- there may be som... ember companies have that may not have a valve ... ability to.....

COMMISSIONER FOERSTER: To the best of your knowledge what percentage of the WAG wells have safety -- subsurface safety.....

MR. ENGEL: Oh, Commissioner Foerster, I'd hate to make a guess on that.

COMMISSIONER FOERSTER: Okay. It's hard for me to grasp the magnitude of the impact if I -- you know, if it's -- if we're talking in some and, you know.....

MR. ENGEL: Well, the.....

COMMISSIONER FOERSTER: .....a few and many and some and.....

MR. ENGEL: .....our conclusion was that based on the difference in these wells that operators may be coming in for a variance based on the well's conditions.

COMMISSIONER FOERSTER: And would that be acceptable, I mean, would -- you know, couldn't we deal with this on a case by case basis?

MR. ENGEL: I think we could.

COMMISSIONER FOERSTER: Okay.

MR. ENGEL: And our point here was to bring up the fact that all wells of this nature are not the same and the risk for these wells are different. So I was trying to articulate the reason for a request that may be coming in from operators.

COMMISSIONER FOERSTER: Okay. Well, that's different than getting rid of the requirement. So, but I think we've -- we're trying to structure the regulations in a broad enough way that we allow waivers, variances.....

MR. ENGEL: Right.

COMMISSIONER FOERSTER: .....special conservation orders. And we're going to tend towards have broad, statewide rules with the opportunity for individual variances.

MR. ENGEL: And we appreciate that option as well.

COMMISSIONER FOERSTER: Okay. Okay.

MR. ENGEL: The point this morning was just to bring up the difference in these kinds of wells and the risk profiles are quite different.

COMMISSIONER FOERSTER: Okay. On (h), I understand your concern about individual conservation orders and other documents and what's going to happen with them. And after we've heard all of the industry comments I'm going to ask if Mr. Regg will come up and testify, answer a few questions I've got for him and addressing how we propose to deal with the COs will be part of that. And so I would ask that you and the other operators that have that concern listen really closely to what he says so that if you still have questions or concerns and I ask you you can tell me what they are.

MR. ENGEL: Yeah. Very good.

COMMISSIONER FOERSTER: Okay.

MR. ENGEL: Commissioner Foerster, would that also include the -- what I refer to as legacy documents that are out that related to this topic?

COMMISSIONER FOERSTER: Yes.

MR. ENGEL: Okay. Very good. Because that's a significant issue for operators is that these documents may not be available and we need to understand what the guidelines and the regulations really are.

COMMISSIONER FOERSTER: Okay. My next.....

MR. ENGEL: Thank you for that.

COMMISSIONER FOERSTER: Thank you. My next question is on our (i)(1), (2), (4) and (5). It sounds like you're asking for more time before testing.

MR. ENGEL: Section (i) on numbers?

COMMISSIONER FOERSTER: (1), (2), (4) and (5).

MR. ENGEL: (1) through (4).

COMMISSIONER FOERSTER: (1), (2), (4) and (5).

MR. ENGEL: The main point, Commissioner Foerster, on (1), (2), (3) and (4) is around allowing us some time for the well to stabilize thermally thereby allowing the valve that was installed to calibrate to downhole conditions and function in the environment in which it's going to be working. And then in addition -- let's see, I don't think that -- those sections refer to the timing component.

COMMISSIONER FOERSTER: Well, reaching stabilized production, you know, that's.....

MR. ENGEL: Okay. Yes.

COMMISSIONER FOERSTER: .....that's timing.

MR. ENGEL: In that respect, yes, but we're asking for some time for that to happen.

COMMISSIONER FOERSTER: Okay. Well, my question to you is so that the Commission doesn't find itself in the position of being put off indefinitely, we'd really prefer a suggestion if 48 hours isn't long enough for a well to stabilize, we'd really prefer what you think a time is and it would be much more tenable for us if we had 72 hours or something like that rather than trust us, we'll call you. So my question to you is to give us a suggestion on what a reasonable, expected time for a well to stabilize would be.

MR. ENGEL: I think that's the -- I think that's a appropriate request.

COMMISSIONER FOERSTER: Okay. And on (4) and (5) we have wording in that says unless the Commission approves an extension of time for testing. Would that not adequately address your concerns about stabilizing?

MR. ENGEL: Well, I -- Commissioner, we added the language there around stabilization for acknowledging the need to have the thermal stabilization take place. Unless the Commission provides an extension of time for testing or the well is in compliance with -- I guess the issue on number (5) would be that we would have to request timing each time we did that without having established an average time for well stabilizing and hoping to avoid requesting and extension of time.

COMMISSIONER FOERSTER: Okay. Well, on this one again I'd ask you if you had something better than 48 hours to offer for a suggested timing?

MR. ENGEL: Okay.

COMMISSIONER FOERSTER: Okay. Now go to (i)(10).

MR. ENGEL: Okay. Often when we look to other agencies to see -- you know, get go bys for what other agencies are doing, we -- for safety valve systems we might look to the MMS. Does the MMS use the standards that you're proposing?

MR. ENGEL: They don't, Commissioner Foerster. I've reviewed those as well and MMS is more conservative than the

API.

COMMISSIONER FOERSTER: And why is that?

MR. ENGEL: I couldn't tell you the reason why.

COMMISSIONER FOERSTER: Okay.

MR. ENGEL: But I know -- if I recall it's approximately half of what API has recommended.

COMMISSIONER FOERSTER: Okay.

MR. ENGEL: I do want to note that we did make contact with some vendors that supply these valves to us and all these valves are designed and tested in the shop on a bench and the expectation is that these valves will hold the expected pressure. And the -- there is also guidelines or established leak rates that companies have established, Halliburton for example, for well -- for a valve that's in service in a well. And that's because of the nature of these valves opening and closing and they're -- they may be -- there may be a leak rate, a very small leak rate associated with these valves due to the nature of the valve itself. So I think based upon the manufacturer's testing for -- shop testing and for in field testing, there is some guidance out there for expected leak rates for these systems. And then API also has an established leak rate, MMS as I mentioned does as well. So we'd like the current Commission to consider these established leak rates in the -- in the proposed regulation.

COMMISSIONER FOERSTER: What -- another question. Is there a problem with the current process that we use, is -- are you -- are we experiencing problems right now with the method we're using?

MR. ENGEL: I would say I can't -- I can't point to a problem with the current system. We'd like to see the State actually acknowledge these established leak rates and have some in there so we know what the actual performance of the valve would be.

COMMISSIONER FOERSTER: Okay. And (j)(3) and (4), let me make sure I'm getting to the right place. We tossed around what your concerns were and let me -- let me very informally, casually describe a process that we're considering changing our wording to and see if this would work. Okay you can't get the wing valve to hold pressure and so you use an alternate valve, we approve it and it works -- and -- and so -- okay. So wing valve's not working, you go to a different valve and either a, it works and we go about our business, we do the test and we leave you until the next time we see you to get things in order.....

MR. ENGEL: Yeah.

COMMISSIONER FOERSTER: .....or b, the alternative valve doesn't work and then you have seven days to get it or the wing valve fixed so that we can do the test. Would that kind of mental -- would that kind of approach address your concern?

MR. ENGEL: The issue that we have is the time in which the current draft requires us to fix the valve, we just don't think it's adequate to actually do that. So time.....

COMMISSIONER FOERSTER: But if neither valve -- if neither your wing valve nor your alternate valve works then you still want as much time as you'd like to take, we shouldn't put a limit on that?

MR. ENGEL: There may -- there could be another valve downstream of the wing -- the wing valve is the valve on the tree, the lateral valve will be the next valve downstream, there's another valve that could be used.

COMMISSIONER FOERSTER: Okay. So if you -- if you are -- let me be more clear. If you're unable to find an alternate valve that would allow you to perform the test, would it not be acceptable to you for us to give you a time period in which to get a valve that will act as well control and allow you to perform the test?

MR. ENGEL: That would -- that would be reasonable if the time frame allowed for that work to be done within that time frame you were going to propose.

COMMISSIONER FOERSTER: What's a reasonable time?

MR. ENGEL: Fourteen days. That's what we propose, 14 days.

COMMISSIONER FOERSTER: So you're -- there would be 14 days when you wouldn't have a valve that could operate as well control or safety valve check?

MR. ENGEL: I don't think that could -- considering the valves we have in place on the tree and on the flowline coming downstream of the wing valve, that situation to happen, I think it's -- the odds of that happening are pretty rare.

COMMISSIONER FOERSTER: Okay. Let's go on.

MR. ENGEL: So I think the question's around the timing, you know, what's a reasonable time to allow us.....

COMMISSIONER FOERSTER: Okay. So your main concern is reasonable time. Thank you. Let's go to (k)(1). Oh, that's the same thing. Never mind, that's the same thing. Let's go to (l) and (m). What are you trying to accomplish by adding the phrase through the tubing string? I didn't see where that added value and I'm just trying to understand what your.....

MR. ENGEL: Okay. We're talking.....

COMMISSIONER FOERSTER: (l) and (m).

MR. ENGEL: Uh-huh.

COMMISSIONER FOERSTER: Because your only proposed changes were -- for the rest of the group, an operator may demonstrate by a no flow test that a well is incapable of the unassisted flow of hydrocarbons to the surface subject to the following as opposed to unassisted hydrocarbons to the surface through the tubing string subject to the following. I'm not sure I understand what value adding through the tubing string brings.

MR. ENGEL: I believe the comment here, Commissioner, was to clearly state that that would be the flow path not through the inner annulus.

COMMISSIONER FOERSTER: Okay. How -- do you do no flow tests through the annuli? I'm sorry, this is.....

MR. ENGEL: Actually we can do a no flow test from the annulus.

COMMISSIONER FOERSTER: Okay. All right. So -- okay. Let's go to (m)(3).

MR. ENGEL: (m)?

COMMISSIONER FOERSTER: (m) as in Michael.

MR. ENGEL: Okay.

COMMISSIONER FOERSTER: I'm not sure I understand the objective here either. Are you saying that you cannot achieve stabilized flow with a subsurface safety valve in place? Oh, (m)(3) was a proposed add by AOGA.

MR. ENGEL: Yes, Commissioner Foerster, the intent of that request was to allow the well to be drawn down and establish some stable flow before the test was conducted.

COMMISSIONER FOERSTER: Okay. Now I'm a little concerned here. Okay. This -- you're trying to establish a no flow so that you don't have to have a subsurface safety valve in the well, right?

MR. ENGEL: Yes.

COMMISSIONER FOERSTER: And so in order to do what you're saying you want to do you'd have to pull the subsurface safety valve, let it stabilize, conduct the test and then if it does flow then you have to put the subsurface safety valve back in. So my concern here is that you've said that well interventions are one of your riskiest ventures, yet here you're purporting -- you're proposing to do something that could require two extra well interventions. Why couldn't we just do the test and if it doesn't flow, it doesn't flow, then you can get the safety valve out of there. But if it.....

MR. ENGEL: Yeah.

COMMISSIONER FOERSTER: .....flows then why do two extra well interventions.

And while you all are talking, for the people who don't have (m)(3), I'm sorry, let me read it to you. It would be a new add to (m) and it says upon notice to the Commission of an upcoming no flow test, a well may be produced without an SSSV for up to 14 days to reach a stabilized condition prior to the test.

MR. ENGEL: And what you just described, Commissioner Foerster, is -- that's a reasonable result of what we requested here. I think that's an acceptable approach.

COMMISSIONER FOERSTER: Okay. I don't have any other questions for you at this time, Mr. Engel, and I appreciate your patience with me.

MR. ENGEL: Commissioner, it's always an enjoyable time appearing before this Board. And I do appreciate the work that's been done to date and I do want to thank the Commission again for the help we received during this. And again we think it's very important that we address these legacy issues that are out there, not only the current draft, but all old issues so we can move forward with clear and concise guidelines for operators.

COMMISSIONER FOERSTER: I did have a couple of more comments for you, if I'm allowed.

CHAIR SEAMOUNT: Well, first of all, Commissioner Foerster, I wouldn't assume anybody's patient with you.

COMMISSIONER FOERSTER: Okay. Fair enough. My first comment is that -- not to, you know, testify or anything here, but a lot of the comments that we received from you guys when we went through them again, if you didn't hear me ask questions about things it -- you know, it either means that our mind is made up or you made a good argument and we're considering alternatives.

The other comment I wanted to make is in your general opening statements you talked about how it's inappropriate to go from half a page to five pages, but I do want to acknowledge that we're going from -- to five pages from half a page plus all these other documents that you're talking about, plus all the individual COs. So if we can go down to five pages from half a page plus the 4/24/92, plus the 3/94, plus the 8/12/98, plus the 11/14/95 and on and on and on and on, I think that we're moving in the right direction.

MR. ENGEL: Just to clarify. I didn't say it was inappropriate, what I said was it was significant.

COMMISSIONER FOERSTER: Oh, okay.

MR. ENGEL: And that was my main point that we're going from half a page to five and it's a lot of new additions to the regulations. Thank you for that.

COMMISSIONER FOERSTER: Thank you.

CHAIR SEAMOUNT: Commissioner Norman.

COMMISSIONER NORMAN: Yes. Just a couple of comments and I'll go now to the more general, Commissioner Foerster's been very specific.

Mr. Engel, you've worked in other regulatory environments, jurisdictions, is that correct?

MR. ENGEL: Yes, I have in the Lower 48.

COMMISSIONER NORMAN: And can you briefly review where else you have worked?

MR. ENGEL: Well, I've worked in most of the Rocky Mountain states, from New Mexico to North Dakota and Kansas to California. So I have experience -- it is dated, it's been more than 20 years ago since I worked down in the Lower 48, but I have worked.

COMMISSIONER NORMAN: All right. So any experience you have then is somewhat dated insofar as what the regulatory practices would be in those states. And I'm not -- I mean, I wanted to set a stage for this. I was going to ask you and if you would care to comment on the current regulations in Alaska related to well safety valve systems compared to the regulatory structure that exists in some of the other jurisdictions you've worked in. But I'll add given the fact that you have not worked there recently that may not be a proper question to put to you.

MR. ENGEL: It's a very broad -- a broad question, Commissioner Norman. The one area that I'm familiar with some of our colleagues in the Gulf of Mexico is the MMS. And the MMS regulations are more what I would call a performance based approach where they say an operator will, for example, maintain well control at all times. And the State of Alaska regulations are more what I would call prescriptive, outlining details and expectations for certain parts of the well. It's a different approach. And we have looked at some of the regulations, for example, in Texas and Louisiana just to get a broad view of how they address these issues. And some do it in various capacities and levels of requirements than Alaska's proposing. So there is -- there is a little bit of crossover. I'm not prepared to get into detail about these states because I'm not that intimate with the requirements, but different states do have regulations affecting safety valve systems along with the MMS.

COMMISSIONER NORMAN: That answers my question. Thank you.

CHAIR SEAMOUNT: Thank you, Commissioner Norman. Okay. Thank you, Mr. Engel. Commissioner Foerster has another challenge for your patience, Mr. Engel.

COMMISSIONER FOERSTER: Mr. Engel, this question is asked of you on behalf of AOGA. Is Aurora a member of AOGA?

MR. ENGEL: (Nods negatively)

COMMISSIONER FOERSTER: No. Okay. Then I'm done with you.

MR. ENGEL: You know, Commissioner, the baseball legend Yogi Berra as we all know had a lot of quotes and one of his quotes I like is to answer your question, I wish I had the answer to that because I'm sick of answering that question.

(Off record comments)

MR. ENGEL: Thank you, Commissioner.

CHAIR SEAMOUNT: Okay. Thank you. Okay. Moving right along. Is there anybody from North Slope Borough here? Commissioner Foerster had some really good questions for them, but I guess we'll have to do it by mail.

Okay. Next on the agenda would be the next -- looks like we have three people from ConocoPhillips Alaska who wish to testify. Are they all -- they're all here, right? Okay. And are you the ones with the picture show? Okay.

I wonder if we should take a little break while they set up. So all three of you be prepared in 10 minutes.

(Off record)

(On record)

CHAIR SEAMOUNT: We're back on the record. Okay. Now we have ConocoPhillips testifying and I assume -- well, first of all raise your right hand everyone, please, all three of you.

(Oath administered)

MR. KANADY: Yes.

MR. HUBER: Yes.

MS. LOVELAND: Yes.

CHAIR SEAMOUNT: Thank you. I assume you all want to be considered as expert witnesses. Ms. Loveland, I think you've already been an expert witness in here and I think you two have also, haven't you. Well, anyway we'll start on the left, please state your name, who you represent, what the subject of your being an expert witness is and your qualifications.

M.J. LOVELAND

called as a witness on behalf of ConocoPhillips, testified as follows on:

DIRECT EXAMINATION

MS. LOVELAND: My name is M.J. Loveland, I'm a Well Integrity Project Supervisor for ConocoPhillips. I have 20 years of experience in the petroleum industry starting with a bachelor of science at the University of Wyoming, umpteen years ago, and a wide range of experience from facilities engineering, production engineering, development engineering and my current position, well integrity. I have a advisory capacity with our safety valve systems up on the North Slope and I also advise Beluga and Tyonek when they have questions and work closely with the Commission -- the engineers and the Commission with questions such as safety valve systems.

CHAIR SEAMOUNT: Thank you, Ms. Loveland. Wyoming is a wonderful place. Commissioner Foerster, do you have any comments or objections to considering Ms. Loveland as an expert witness?

COMMISSIONER FOERSTER: None whatsoever.

CHAIR SEAMOUNT: Commissioner Norman?

COMMISSIONER NORMAN: No objection.

CHAIR SEAMOUNT: Okay. You are -- Ms. Loveland, you are designated an expert witness. Next.

JEFF HUBER

previously sworn, called as a witness on behalf of ConocoPhillips, testified as follows on:

DIRECT EXAMINATION

MR. HUBER: My name is Jeff Huber, I'm currently a field wide Operations Superintendent at the Kuparuk River field. I have 25 years experience in the industry. I hold a bachelor of science in mechanical engineering from the University of Alaska, Fairbanks. I've held various positions in the industry and worked in various locations including facility engineering assignments, operations supervision assignments, corrosion management and other asset integrity programs working at

Prudhoe, Kuparuk as well as two different fields in the Cook Inlet area.

CHAIR SEAMOUNT: Thank you, Mr. Huber. Commissioner Norman, do you have any questions or objections?

COMMISSIONER NORMAN: No questions or objections. And just again to thank you all for stating your qualifications and to remind all of us that we are making a public record that may be read a year or two or three or five years from now. So it is very important that whoever reads that record know not just the name of the speaker, but their background and that way they can weigh their comments. That's why we put you through that.

CHAIR SEAMOUNT: Mr. Huber, you are designated a witness. What's your problem.

COMMISSIONER FOERSTER: You didn't ask me if I had any objection.

CHAIR SEAMOUNT: Oh, I thought I -- I'm sorry, Commissioner Foerster, I apologize profusely. And please be patient with me.

COMMISSIONER FOERSTER: I have no objections.

CHAIR SEAMOUNT: I didn't think you did, I was assuming too much. Thank you, Mr. Huber, you are designated as an expert witness. Mr. Kanady.

RANDALL KANADY

previously sworn, called as a witness on behalf of ConocoPhillips, testified as follows on:

DIRECT EXAMINATION

MR. KANADY: Yes, my name is Randy Kanady, I'm a Staff Drilling Engineer with ConocoPhillips. And my current job responsibilities include regulatory issues dealing with ConocoPhillips. I am a registered professional engineer in petroleum engineering with the State of Alaska and I have over 20 years experience in the oil and gas industry in the State of Alaska in positions from production engineering to wells and drilling engineering to health, safety and environmental positions. I have an undergraduate degree in petroleum engineering and a master's degree in environmental engineering.

CHAIR SEAMOUNT: Your turn, Commissioner Foerster.

COMMISSIONER FOERSTER: Where did you get your degrees?

MR. KANADY: My undergraduate degree was from Montana Tech in petroleum engineering and my master's was at University of Alaska, Anchorage.

COMMISSIONER FOERSTER: Okay. I have no objections to you as an expert witness.

(Off record comments)

CHAIR SEAMOUNT: Commissioner Norman, do you have any comments or objections?

COMMISSIONER NORMAN: No comments, no objections.

CHAIR SEAMOUNT: Mr. Kanady, you are designated as an expert witness.

(Off record comments)

MR. KANADY: I guess I'd like to start out to make sure that the Commissioners have our comments that were submitted on March 8th. I do have extra copies here if you need. It would be handy as we go through the testimony to follow along with the comments. So if you need a copy of that I have a copy.

CHAIR SEAMOUNT: I think it would be easier if I had a copy instead of go -- running through the record here, it's about four inches thick.

MR. KANADY: And then I'm also providing the Commission with a copy of our presentation today as well.

CHAIR SEAMOUNT: Excellent.

COMMISSIONER NORMAN: Mr. Kanady, while you're handing that out, what you just referred to for the record is a March 8th letter and it's stated by J.S. de Albuquerque, is that correct -- signed by?

MR. KANADY: Yes, that's Conoco's comments on the proposed regulatory changes to 20 AAC 25.265.

COMMISSIONER NORMAN: And that is what you have just provided to us and that is in the record. Thank you.

MR. KANADY: Yes. Conoco appreciates the progress to date in developing the current draft safety valve system regulations. Conoco's top priority is environmental and safety performance so we applaud the current SVS strategy that's currently applied in Alaska. Current requirements for SVS systems on all onshore wells puts Alaska among the most protected in the industry. So when we propose changes they clearly need to address defined risk, including the potential frequency of an incident, the probably consequence of that incident and the potential impact of the solution. And that will be a central theme as we work through our comments.

COMMISSIONER NORMAN: Mr. Kanady, I'm going to interrupt you there and that'll save asking a question later on. But you've indicated that our regulations, if I understand you, right now are at the forefront of the regulatory environment in the United States; is that a -- that's my words, but.....

MR. KANADY: Yeah, in our review group we had a participant from our corporate office, Jerry Dethlefs and we asked him to review that issue and his response was that most -- that Alaska is in the forefront.

COMMISSIONER NORMAN: What state would you say has the most stringent regulations in the United States?

MR. KANADY: Commissioner Norman, I'd have to request that we get back with you on that, we could.....

COMMISSIONER NORMAN: That's a fair answer. Thank you.

MR. KANADY: So continuing on. Conoco is in favor of regulatory changes that reduce risk without introducing additional hazards such as additional well intervention and potential increase in spill potential. And for some of the proposed changes Conoco is not able to identify potential risk reductions. And so we urge the Commission to only implement new regulatory changes where applicable risk reduction is identified.

And I apologize for the repetitive nature of this, but in our submitted written comments, there's several regulations that we would like to consider critical regulations. And there's a number of comments in our written comments that we don't have time to address today so we'll be only addressing the critical issues here listed below. And Jeff Huber will be reviewing the SVS linking regulation, (c)(5) as well as a fire and gas detection ESD in (c)(7). M.J. Loveland will be reviewing the SVS subsurface safety valves for onshore oil and gas wells, (d)(2) and (e) as well as the performance testing, (i)(1) and (i)(11) and the bubble tight testing, (i)(10) and (i)(11). Jeff Huber will be reviewing the low pressure set points in (i)(9) and the positive sealing devices in (j)(4). And there are two issues that we'd like to just briefly review towards the end and I'll be reviewing Section (c)(9) in regards to the Commission approval of the SVS systems and the proposed comments that we're making in regards to (j)(1),(2) and (3) for having an option to continuously man a system that has not met the requirements.

So with that I'd like to hand it over to Jeff Huber.

MR. HUBER: Thank you, Randy. Thank you, Commissioners. Paragraph (c)(5) in the proposed regulation requires that safety valve system controls be linked so that if one well has an actuation of its SVS system it'll shut in all wells that share a common flowline. There's a couple issues I'd like to express today on that. One is with terminology. By the term common flowline the Department of Environmental Conservation has already previously established a fairly formal definition of what flowline is and common flowline. And that refers to cross country pipelines that link multiple drill sites to their central production facility or gathering center or flow station, you know, whatever term you'd like to use for the central facility.

The concern as currently written is if we were required to link multiple wells that share that common flowline, you're -- as Mr. Engel previously mentioned, you'd be talking multiple wells on a given drill site, in fact, all wells on a given drill site as well as peer wells on other drill sites that share that flowline perhaps several miles apart. We believe or we -- it is our hope that the intent of the draft regulation was to address what we sometimes refer to as twinned or tripled wells, wells that share a common well line.

The subsequent comments I'll be making will address either situation, again it depends on what the Commission's intent originally was.

The other concern is -- surrounds the technical basis for the -- for this requirement. I think it's important to note that the purpose of the safety valve system is not intended to be the single, protective element in the oil field that protects against any leak anywhere. As you know, the safety valve system is intended to protect against a significant failure near the well and to secure the well in the event of such a failure, you know, such that the well will no longer contribute to a release of hydrocarbons. I guess to illustrate the point, a small leak somewhere miles downstream on a common flowline will likely not trip the SVS as currently defined and the term is used in the industry.

I think it's important to note that there's other protective devices in the overall system that provide such protection. Again the SVS has a very specific purpose and I'll illustrate that further in a moment.

It is important to note that the wells currently already are linked via the shared well line. And I believe as Mr. Engel mentioned, if only one well trips initially the remaining well becomes no different than a nonshared well. And again that independent safety system will trip when the well line pressure drops below its low pressure sensing device set point affording -- you know, affording the equivalent level of protection.

To illustrate this in a pictorial fashion, again just to make my comments clear, what we refer to as well lines are the.....

(Off record comments)

MR. HUBER: What we refer to as well lines are the pipelines that connect each wellhead to a production manifold, typically in a drill site manifold building or other arrangement on the Slope. What we refer to as flowline, flowlines and defined by the DEC, those refer to the pipelines that transport the commingled production from your drill site buildings to your central production facility. And again that could be a dedicated flowline transporting production from one drill site to the facility or it could be a shared flowline, a common flowline that commingles production from multiple drill sites and, you know, up to several hundred wells.

To illustrate the point about why linking adds little or no value, we need to consider the purpose of the safety valve system and what happens in the event of a failure that would likely be the cause of a safety valve system to trip. One might be you get a leak in the -- in a single well line. In that case the safety valve system detects the leak and shuts in the well, that is its purpose.

Now when you look at -- again what we believe the intent of the regulation was was to address shared well lines, we believe that to be the configuration that the Commission had intended to address. In that case if -- in the event of a leak on such shared well line, it's very likely that both wells' safety valve systems would detect that leak, given the drop in pressure, being that they're linked hydraulically through that flowline already and both wells would shut in. However we acknowledge that it is possible that at least initially maybe only one well's SVS may detect that leak. In that event it would shut in its -- that well's production, but at that point in time that is really no different than a nonlinked well. The shared well is out of the picture and really at that point it's no different than the remaining well seeing the leak as if it didn't have a twin and it would shut in as well. So we postulate that you -- in this configuration the nonlinked systems that currently exist are indeed effective.

The disadvantages of linking from our perspective would be increased spill potential, I believe you heard earlier that the long runs of hydraulic tubing outside, exposed to the elements, exposed to mechanical damage, could indeed be a source of spills of hydraulic fluid. We're also concerned about increased aggregate risk, that is any risk reduction that may be possible with a linked system we also need to consider the increase in risk associated with the fact that when we defeat a wellhead's safety valve system for well work, for example, currently we defeat that safety valve system, we're continuously manning the well as currently defined in the draft regs, but with the linked system we're not only going to have to defeat the safety valve system for that well, but also the linked wells. So at any given time wells undergoing well work that happen to share a common well line, we'll end up having to defeat more wells than we do currently. So in general there will be a greater percentage of time that wells will be operated with a defeated system that don't need to be operated in that fashion.

Again depending on the intent of the regulation, whether it truly was intended to address wells sharing a common flowline or a common well line as I've interpreted, that cost for install a linked system could be very high.

Another concern is during performance testing because these linked systems would be prescribed by regulation, it is assumed that they would also need to be tested with each test cycle of the safety valve systems, that is every six months. During that testing we would not only have to trip that particular well's SVS, but any wells that are linked to it and vice versa during each cycle. That would result in increased -- you know, again in a higher number of wells shut in during that test cycle. It would also require increased cost in manpower for performance testing. Again it's a more complex system, more steps involved.

With that more complex system we believe that there would be additional or incremental shut in production due to inadvertent trips. The -- such a linked system would inherently be less reliable due to portions of the system being exposed to cold weather, the hydraulic fluid used in these systems would increase in viscosity. That has proven to prevent -- present reliability problems in these systems. Again these are issues that we believe we could manage, we could deal with, however they would present difficulties and inherently we would end up with a less reliable system.

So to summarize we believe protections already exist and are effective. That consists of this -- the current safety valve systems that detect low pressure on that given well line and eliminate that well as an energy source. There's other system devices that prevent backflow and leaks in downstream portions of the system. Again the well's SVS or safety valve system is -- has a very specific purpose.

The cross country common lines which are defined as flowlines and well line pressures are continuously monitored and alarmed at the central processing facility and, of course, we have full-time staffing to respond to such alarms.

The requirement to link our SVS systems would add cost, risk and complexity. And currently we -- it is unclear what the benefit of SVS linking would be. We are unable to establish, you know, some clear historical drivers or a clear regulatory basis for the linking requirement. As such our recommendation is to eliminate the requirement as currently written in paragraph (c)(5).

Are there any questions before I move on?

COMMISSIONER FOERSTER: I'd prefer to save my -- I've got -- I'll give my questions at the end if that's okay with you.

COMMISSIONER NORMAN: I'll ask one right now because it's on a fairly narrow point on the linking. Assuming that the Commission is of the opinion that there is some benefit to linking, are you able to quantify the cost, you mentioned increased cost, can you give us some idea of order of magnitude to your company's operations?

MR. HUBER: We haven't done a detailed cost estimate, Commissioner Norman, because we haven't completed the design work. We do recognize that that design would have to include provisions to help mitigate some of the pitfalls I previously mentioned. So I -- no, I -- it would be a guess if I gave you a number right now. And we could provide a cost estimate within a reasonable period of time if it's required.

COMMISSIONER NORMAN: Well, would it right now just on order of magnitude, would it be closer to 100,000 or closer to a million?

MR. HUBER: In order to answer that I need to know would the requirement apply to all wells sharing that common flowline, in other words cross country flowline or a common well line?

COMMISSIONER FOERSTER: Linked wells.

MR. HUBER: Linked wells on a common well line, wells sharing a common well line between the wellhead and the manifold building, I would say it would be more on the order of 10 to $20,000 per well.

COMMISSIONER NORMAN: Okay. Very well. Thank you.

MR. HUBER: Moving on, paragraph (c)(7) requires that structures containing multiple wells in a common area have a gas detection and fire detection system that will immediately shut in all wells located within the structure. There are a few concerns we have with this requirement. One, it's a very prescriptive requirement and may not be appropriate in all cases. Fire and gas design is a fairly complex process by which one must consider not only the hazard, for example, is it a gas well, is it an oil well, how big of a well is it, what -- et cetera, but also the exposures, you know, what are my surrounding exposures that I'm trying to protect against. One also needs to consider okay, what is the affect of an ESD on a downstream piece of equipment. And it needs to take a fairly wholistic approach to designing a fire and gas and ESD design or system.

For example gas detection in our production facilities, it's often a staged action scheme, in other words the first action upon initial gas detection is rarely an emergency shutdown. Oftentimes, and again this is appropriate in the event of a small leak, gas leak, for example, when you detect gas the first action might be alarm at the central control room and increased ventilation rates. The benefit of doing that, one, helps rule out things like false alarms or faulty detection equipment and not shut down the process needlessly;

two, it helps mitigate the risk or the hazard, by increasing ventilation you can keep that gas, if there is a real gas leak, you can keep it from reaching dangerous levels; and three, by buying yourself that time you can give personnel time to respond in an appropriate fashion. There are cases where taking an E -- you know, ESDing or emergent -- taking an emergency shutdown of the process on gas detection may be the least desirable action to take. Again an example might be in a process module if you have a leak on your flare system, if you were to have a -- detect gas in that module you may not want to take an ESD and blow down the action because that would actually make the problem worse.

And again that whole -- the whole risk and action matrix needs to be considered very carefully and as currently stated the regulation is fairly simplistic, fairly prescriptive and may not be appropriate in all cases.

I gave you examples about gas detection schemes with fire detection, very similar issues when you look at NFPA requirements and if you look at what industry practice is, typically there's a multitude of schemes that could be employed, things like cross zoning, implementation of time delays, other applications of technology that are more appropriate than a simple, you know, shut down the facility if you have one fire detector go off.

I mentioned things that need to be considered when -- with an ESD philosophy. In fact the federally mandated Process Safety Management regulation and some of its components require us to do detailed risk assessments of our facilities and design an emergency shutdown system that is appropriate again given the hazards involved, given the exposures and the overall risks.

It's also important to point out that there may be some, as currently written, some interagency consistency issues. Currently the State of Alaska's Office of the Fire Marshal oversees and regulates the requirements for fire system design. And again those requirements take into account things like occupancy, size, type of hazard, et cetera. And we just want to ensure that any requirements in the SVS regulations are consistent with those other requirements we're held to.

In summary ConocoPhillips recommends that a performance based standard be implemented rather than a very prescriptive standard. Again if we could better understand the Commission's concerns in the area of fire and gas detection for structures containing multiple wells, we -- it is our belief that we can work with the Commission to ensure that any system employed is mutually acceptable. And finally it's important to point out that with a -- a performance based standard is also desirable in the sense that it also allows flexibility as changes in technology become apparent or new technology becomes available we can adapt accordingly.

That completes my commentary on this paragraph.

CHAIR SEAMOUNT: Commissioner Foerster, do you have any comments, questions?

COMMISSIONER FOERSTER: I'm going to save mine.

CHAIR SEAMOUNT: She's saving. Commissioner Norman?

COMMISSIONER NORMAN: None at this time.

CHAIR SEAMOUNT: Okay.

MR. HUBER: Thank you.

CHAIR SEAMOUNT: Thank you, Mr. Huber.

MS. LOVELAND: I'm going to address ConocoPhillips' comments on the subsurface safety valves. And our recommendation at this time is the proposed regulation (d)(2) onshore safety valves or onshore subsurface safety valves be deleted. And I'll go through some history here for you.

Back in -- at the beginning of Prudhoe Bay in 1977 and the beginning of Kuparuk in 1981, that's when the use of onshore subsurface safety valves were adopted. And at that time there was very little Arctic engineering experience. And we used those subsurface valves because of inexperience with what was going to happen with the permafrost and production.

Since then or more recent history, 1994 the Commission adopted Conservation Order 348 for Kuparuk and 345 at Prudhoe Bay. And I'm just going to read through some of the findings from those conservation orders that actually removed the requirement of having subsurface safety valves.

So finding number 12, the Commission has no record of subsurface safety valves being used in Alaska to prevent uncontrolled flow from the surface from an on -- to the surface from an onshore well. And I have a side note that isn't part of the finding, but my side note is however this -- having subsurface safety valves in wells have actually caused wireline incidents and uncontrolled flow to surface during maintenance operations. So they haven't prevented problems, but they've caused problems in the past.

Finding number 13, higher operating costs for the State as well as for the operators' testing and maintenance.

Number 14, a subsurface safety valve is -- can impede production or prohibit some types of completions, ESP wells, surface powered jet pump wells, those particular completion types are not subsurface safety valve friendly.

And then some of the conclusions from these conservation orders are subsurface safety valves may reduce ultimate recovery due to higher operating costs.

Finding number 2, subsurface safety valves in onshore wells in Alaska provide limited benefit to public safety, environmental protection and resource recovery.

Conclusion number 3, experience and new technology have reduced the danger to casing integrity from freezeback and thaw cycles in the permafrost.

Finding number 4, the probability of early detection and response of an accidental release is much greater now than it was in 1981 when the subsurface safety valve guidelines were originally adopted. And eliminating subsurface safety valves will not contribute to waste and it may contribute to greater ultimately recovery.

And so these findings that the Commission adopted in 1994, ConocoPhillips believes actually still stand. The reasoning behind having -- removing the requirements for subsurface safety valves is still valid.

However ConocoPhillips does agree that for onshore or for offshore events subsurface safety valves actually decrease the consequence of a catastrophic event. And some of these consequences are a collision with a marine vessel, a huge ice storm, et cetera. And they do decrease the consequence is something catastrophic does happen. So if we're onshore those particular hazards do not exist, we don't have -- you're not going to be hit by a marine vessel or have a huge ice storm that could impact the wells sufficiently that they would require a subsurface safety valve. So what could happen for an onshore requirement of a subsurface safety valve. An airplane impact. It's possible, but not very likely. Granted if it did happen the consequence would still be -- it would still have a high consequence, but the likelihood would be very, very low therefore the risk level is very, very low. Drilling impact, possible. It's probably happened, in fact, I know anecdotal evidence that has happened, however it's been mitigated with using back pressure valves during rig moves in the wells where the rig is going over top of. So it's mitigated with a similar method as a subsurface safety valve, however it doesn't cause operational issues.

In addition we would like to encourage the Commission to reword Section (e). Rather than reading the whole thing I'll just read the underlined part. Rather than all gas wells to reword it to say dedicated gas injection wells. And our comments for this are very similar to AOGA's in that not all gas injection wells are the same. A dedicated gas injection well at Prudhoe Bay injects 250 million mcf a day, a water alternating gas well, a WAG well at Kuparuk, might inject 10 mcf a day for six months a year. They're very different creatures. The consequence of a catastrophe for these two different types of wells are on complete different ends of the spectrum.

So we request the Commission to provide your risk assessment to where these regulations are based.

ConocoPhillips did a risk assessment, an anecdotal risk assessment, which showed that the likelihood of the wire -- of having wireline incidents increased, personnel risks increased and spills increased while we're operating and maintaining and testing subsurface safety valves and it doesn't actually reduce the likelihood of a catastrophic failure. Therefore it doesn't impact the risk level in a positive manner.

COMMISSIONER NORMAN: Ms. Loveland, on that narrow point, one of your earlier slides, slide 10, it says eliminating subsurface safety valves may contribute to safer well operations. Is this the point that makes our.....

MS. LOVELAND: Yes. Yes, sir, it does.

CHAIR SEAMOUNT: I guess one thing that we've been remiss in saying is that when you describe these she should probably state which slide this is you're speaking off of. And we need to introduce this into the record, is that correct? Okay.

Sorry about that.

MS. LOVELAND: Thank you. I'll -- we're on slide 13. So right now we recommend that (d)(2) be deleted and (d)(3) -- (d)(2) be deleted and all of those special case wells could be handled under (d)(3), those wells that the Commission feels actually that there is a benefit for subsurface safety valves, could be handled under the citation (d)(3). And (d)(3) allows the AOGCC to require subsurface safety valves after notice and an opportunity for a public hearing.

Any questions on subsurface safety valves?

CHAIR SEAMOUNT: Are you still holding your questions?

COMMISSIONER FOERSTER: Yes.

CHAIR SEAMOUNT: Commissioner Norman, any questions?

COMMISSIONER NORMAN: No questions.

MR. KANADY: I just have one comment in regards to (d)(2).

Our -- Conoco's first recommendation is to delete (d)(2). If that is not upon the Commission's review an appropriate solution then we do have comments in regards to (d)(2) that we'd like the Commission to recognize in their review.

COMMISSIONER FOERSTER: Wouldn't it be appropriate to give those now, I mean, this is the hearing.

MS. LOVELAND: Yeah, they are in the written comments.

MR. KANADY: They're in the written comments.

COMMISSIONER FOERSTER: Okay. And I'll probably be asking questions about those.

MR. KANADY: I just wanted to point out we have actually a double comment on (d)(2) that's -- and it's thin.

MS. LOVELAND: It's shoot for the stars and hit the moon.

CHAIR SEAMOUNT: Okay.

MS. LOVELAND: And (e)(3) should be modified for dedicated gas injection wells only. I missed a bullet on slide 13.

If there's no questions on subsurface safety valves I'm going to go into function testing. And this slide 14 is a little bit difficult to read, but I wanted to point out what the pilots looks like, what the hydraulic panel looks like and where your sub -- your surface safety valve is located. These are high and low pressure pilots and these proposed regulations currently oversee low pressure pilot settings. This is a hydraulic panel that basically operates all of the safety devices in this particular wellhouse. And your surface safety valve is this valve right here. And there's another picture on the following slide that shows a better picture of what a surface safety valve looks like.

ConocoPhillips wants to comment on the difference between function testing and performance testing in relationship to (i)(1) and (i)(5), but first I wanted to talk through what actually a performance test is. Performance test is just a mechanical test that tells you that your system actuates and it works, you isolate the panel, you trip your panel and you can see that your valve actuates. And on the next photo you'll actually be able to see how you can -- how it's indicated that the valve actuates. You can do this with the well shut in or you can do it with the well online and it shuts the well in, but the well does not have to be in service to do a function test. Conversely to do a performance test the well ideally is -- has been brought online and it's producing at a stable or injecting at a stable pressure and rate. You collect your flowline information, isolate your hydraulic panel, trip your pilot, note the pressure that your pilot trips at, your surface safety valve closes, close your wing, record the pressure that the subsur -- that no pressure gains after the subsurface safety valve trips, open your wing and then watch for the subsurface safety valve. And the whole process takes 10, 15 minutes if everything goes as planned, can take longer, can be much shorter. However you're only testing whether this -- this particular valve you can see here, the surface safety valve, holds pressure and the subsurface safety valve holds pressure and these normally should and as -- they should as they are designed, however you can tell if the system works and operates just by doing the function test.

So on slide 15, this is a photo showing a closed surface safety valve. There is a valve stem that sticks out about three or four inches on the end of every valve and that's how you can tell that it's been actuated shut. So this particular well has -- the surface safety valve is shut.

The two proposed regulations that we were -- we'd like to comment on are (i)(1), a well shall be performance tested within 48 hours when a surface safety valve or one of its components is installed or replaced; and (i)(5), operations that directly affect the surface safety valve performance will require a performance test within 48 hours after the well returns to service.

As it's written anytime we do wireline work and we gag a pilot or anytime there's minor maintenance done to the panels, change a hydraulic hose, change the pilot out, we'll have to have a performance test. And this will be a drain on the Commission as well as on the operators due to the time required and 48 hours to notice the -- or 24 hours depending on your location, notice having a witness test, et cetera, when we can suffice for safety that this well is safe to be online with a function test.

So what we propose, ConocoPhillips proposes a new (i)(1) and delete (i)(5) as it's repetitive with the new (i)(1). A well surface safety valve system be function tested within 48 hours of when the surface safety valve or one of its components is installed or replaced. In addition if the two valves that hold pressure, the surface safety valve or the subsurface safety valve is installed or replaced a performance test is required again within that 48 hour period.

Any questions on that?

CHAIR SEAMOUNT: Go ahead, proceed. Please proceed, Ms. Loveland.

MS. LOVELAND: Okay. The next area that we'd like to comment on is bubble tight testing which is actually (i)(10) and (i)(11). The API recommended practices 14(h), the allowable leak rate on surface safety valves and subsurface safety valves is 6.3 gallons per hour or gas production -- of liquid and gas production of 900 standard cubic feet per hour. AOGA had testified with these particular comments as well.

Some additional information is this is the exact same leak rate of the proposed regulation (m)(1)(a) with a no flow test. ConocoPhillips would recommend that we use the RP 14(h) both for (i)(10) and (i)(11) in addition to (m)(1) and (m)(1)(a) as the recommended practices 14(h) was developed for the specific liquid leak rate of surface and subsurface safety valves. It's a quasi industry standard, not all industry is following that, you know, MMS has a different one, however it is a good industry standard out there. It -- the liquid leak rate is measurable and it's very, very little. You could have a visual, for those of you who are visual, it's slightly more than a five gallon bucket being dribbled full within an hour. The difference between having a bubble tight test and allowing a slow leak rate is going to be a difference in how often you have to change out your valves. It's going to reduce operating costs and reduce maintenance costs. And thus the purpose for ConocoPhillips recommending that you add the 14(h) allowable leak rate in -- as part of the regulation.

Any questions on bubble tight testing?

CHAIR SEAMOUNT: No.

COMMISSIONER FOERSTER: I have questions, but I'm going to save them.

MR. HUBER: Jeff Huber again, starting on slide number 17. Dealing with low pressure set points as prescribed in draft regulation paragraph (i)(9). (i)(9) currently requires the actuation pressure of the low pressure detection device installed on injection wells to be greater than 50 percent of the injection tubing pressure. Our comments will focus around our position that that has a significant impact on water injection wells.

At Kuparuk water injection tubing pressures range from 940 psi to over 2,900 psi. It's almost a factor of -- well, it's approximately a factor of three to one. Currently the pilots, the low pressure pilots or the actuation devices at Kuparuk are set at 700 psi. The reason they're not set at 50 percent or higher is that if they were we would have system stability issues and if this regulation were implemented we would also have to retrofit, you know, hundreds of wells which is costly and we would have to develop -- because of this variability in well operating pressure, we would have to have custom set points throughout the field. You know a wide range of set points is inherently more error prone and tedious to manage than say a single set point as currently in place.

However the real issue, the real impact to -- from an operational perspective would be the adverse system affects caused by such a high set pressure. If we were to set a single set pressure or even a range of set pressures to try and take into account the variability of the wells, the issues that would result can be boiled down to basically being called -- caused by having a very dynamic system. Again you've got a wide range in tubing pressures to begin with and those pressures change over time, again a very dynamic system. Those system pressures change because of routine water flood and enhanced oil recovery operations. We direct water injection to various areas of the field over time, we change how we inject water and so pressures are constantly changing, constantly a moving target. The wells themselves, you have changing wellbore conditions, changing reservoir conditions. Also system pressures change for something as simple as we take a water injection pump down for maintenance.

And what we found is that when the set pressures of these pilots are too high, again in water injection service, having a pump trip off line can actually result in multiple wells tripping off line due to their SVS, safety valve systems actuating when -- not because there's a concern or a leak or a hazard that needs to be mitigated, it's just because the system pressure has taken a low dip. And what that does is if that happens when say during, you know, adverse weather conditions when we can't immediately respond to get out and restore the well on injection, it can cause some serious pipeline and well integrity issues mostly associated with freezing.

The 50 percent of injection tubing pressure requirement is appropriate for wells in gas service. And that mainly has to do with the fact that gas service you're dealing with a compressible fluid, inherently you have more stable system pressures, they'll be less of a pressure drop if there is a mass balance change such as, you know, when a leak occurs or in some of these operational scenarios I described. So as such you need a higher set point on your low pressure pilot. In other words you can set it higher to make it more sensitive to detect a failure and not adversely affect your operation.

However water injection systems are just the opposite, it's an incompressible fluid, inherently you're going to have a less stable system pressure and well injection pressure. There's more variability in those pressures when elements of the system change. Inherently you get a more dramatic pressure drop if there was to be a leak or some sort of a failure. And what that does is it allows you to use a lower set point to achieve the same level of protection.

In summary our current injection well set points have proven to be appropriate, you know, they were developed over years of trial and error and looking at system dynamics. They've proven to be reliable for the intended purpose, yet resilient to nuisance trips. We still have some, but they are not chronic. A higher set point would add the operational and integrity risk I described a moment ago. And we feel that additional risk is not justified or offset by a commensurate risk reduction benefit.

Our recommendation is to make this 50 percent of injection tubing pressure set point requirement apply only to gas injectors. If that is not acceptable to the Commission then we ask that separate requirements and different requirements apply to gas and water injection wells. And so our proposed change would be just to be clear on that, to change the current wording on paragraph (i)(9) to only apply to gas injection wells.

If I may move on.

CHAIR SEAMOUNT: Yes, please.

MR. HUBER: The last topic I'll be speaking on today is dealing with the positive sealing devices provisions described in paragraph (j)(4) of the proposed regulation. For the record I'm currently talking from slide 19.

In summary the draft regulation prescribes some very specific time requirements for repair of the positive sealing devices, when we need to retest after those repairs are done, et cetera. Just to summarize the positive sealing devices are not part of a safety valve system, they perform -- they do not perform a safety function. What they do as you know is allow testing of the safety valve system, they're a peripheral device that facilitates that testing no different than some of the portable test equipment that's being -- you know, that's carried from well to well during the course of testing.

The basis for prescribing definitive time requirements for the repair of those positive sealing devices is unclear. The draft regulation does prescribe very specific time requirements for testing of the safety valve system itself. Such safety valve systems need to be tested every six months, not to exceed 210 days. As long as that requirement is met then it would appear -- it would seem that compliance is achieved.

The -- again the positive sealing devices such as wing valves, as long as we repair those in a fashion and in a time frame that facilitates the required safety valve system testing then it would seem that compliance is achieved. So our recommendation is to simply the regulation and eliminate a specific number of days that the positive sealing device needs to be repaired in, just that -- whatever that number of days is we have to do our safety valve system test within the six months, not to exceed 210 days.

That completes my testimony.

CHAIR SEAMOUNT: Thank you, Mr. Huber.

MR. KANADY: This is Randy Kanady, and appreciate the Commission's patience as we work through this. We have two -- well, actually three slides left. So we're almost done.

A couple general comments in regards to part (c)(9).

CHAIR SEAMOUNT: That's slide 20, right?

MR. KANADY: That's slide 20, yes, it is.

CHAIR SEAMOUNT: I keep forgetting that too. So.....

MR. KANADY: This comment is in regards for the Commission to approve SVS systems within one year of those systems that are currently in place and Conoco requests that this provision be changed that will require industry to meet the required regulation (c)(1)(2)(a), if it doesn't meet it, the system's either shut in or a waiver or variance is obtained requiring the Commission to approve all systems currently in place would require significant work on both sides and we're concerned with additional work without additional benefit.

The final comment that we have -- Commissioner Foerster, are you going to hold your comments to the end or -- okay.

The final comment or regulation we'd like to comment on is in regards to Section (j), both (1), (2) and (3) in that section. This is in regards to if SVS fails a performance test the component must be repaired or replaced or the well shut in as follows. Conoco would -- is requesting that an option be included there to have that particular well continuously manned to allow it to remain online while it is being repaired or if we can't continuously man it we shut it in. And this would be consistent with regulation (K)(2).

So to close out our testimony, slide 21, AOGCC is proposing to make considerable changes to 20 AAC 25.265 which will have significant impact statewide. And these regulatory changes would have substantial impact both on field operations and equipment installations and Conoco believes the proposed regulations would result in both increased manpower and cost for both the Commission and the industry. And there have been substantial comments submitted both today and in writing and we -- Conoco requests a -- call it a collaborative work session with AOGCC and other interested parties on any unresolved issues today before a final hearing.

Again we'd like to thank the Commission for your patience and we're available for questions.

CHAIR SEAMOUNT: Thank you. And we'll start with

Commissioner Foerster.

COMMISSIONER FOERSTER: Okay. Thank you all for your detailed review and comments. Let's go first to (c)(7). You talk about long houses, are you referring to manifold buildings when you say long houses?

MR. HUBER: No, Commissioner. This is Jeff Huber. By long houses we refer to particularly a somewhat unique style of wellhouse in the Kuparuk area in the CPF 3 area. They're independent structures with partitions between each well, but they do have doorways connecting adjacent well bays and again we feel that the regulation as written could be a bit gray in terms of interpretation and.....

COMMISSIONER FOERSTER: Okay.

MR. HUBER: .....we just sought clarity on how those would be treated.

COMMISSIONER FOERSTER: So CPF 3 area's the only place that this applies to your knowledge?

MR. HUBER: To my knowledge.....

COMMISSIONER FOERSTER: Okay.

MR. HUBER: .....in our areas of operation, yes.

COMMISSIONER FOERSTER: Do those long houses have fire and gas detection?

MR. HUBER: No, they do not.

COMMISSIONER FOERSTER: Okay. And the fire marshal doesn't care that they do or not -- don't?

MR. HUBER: I don't know the level of care, I know the fire marshal has been involved -- the fire marshal was involved in the design and original permitting of those structures.

COMMISSIONER FOERSTER: Okay.

MR. HUBER: And special provisions were required at that time.

COMMISSIONER FOERSTER: Okay. And when you gave examples of the appropriateness or inappropriateness of the proposed regs, the examples you gave referred to central production facilities. Could you give me similar examples that refer to these long houses? You gave me an example of what -- why this would be an awful thing if we applied them to CPF 1, 2 and 3, and we'd never do that, but we're talking about wellhouses, so.....

MR. HUBER: An example when you would not want to take an emergency shutdown of a well or group of wells in a high gas -- upon gas detection?

COMMISSIONER FOERSTER: yeah.

MR. HUBER: Yeah. One example would be you have a group of wells in a common structure and let's say you get some gas, let's say it's a real gas release, let's say that source of that gas is a minor leak up -- out one of the surface casing annuli, like out through your conductor. Taken literally the regulation would require shutting in that group of wells upon initial gas detection when a more appropriate action may be to again increase ventilation rates, sound an alarm, allow somebody to investigate before taking that action which I would submit would be more appropriate because you're not in an emergency condition in that case. In some cases you can also get some minor accumulations of gas just due to what we call swamp gas, surface accumulations of hydrocarbon gas that are not really part of that well. So again a more logical approach to fire and gas design would provide for some alarming, some other actions to be taken prior to an emergency shutdown. The downside of taking an emergency shutdown again is shut in production, sometimes it can have a negative affect on downstream processing equipment. Again any sorts of upsets in our facilities does cause -- can cause other problems.

COMMISSIONER FOERSTER: Can you think of any examples where not having this regulation in force would cause a bad -- would be bad, would.....

MR. HUBER: Where not having.....

COMMISSIONER FOERSTER: Where you get your gas release and not shutting in all the wells would be worse than shutting them in?

MR. HUBER: If -- let me check the regulation here. Yeah, for example, a gas injection well. If you -- let's say you do have a minor gas release, by shutting in the gas injection well you can actual -- well, you will actually increase the system pressure which will make the rate of gas release increase which is counter to what is appropriate in that case. An appropriate system design might be shutting in some upstream equipment, not the well itself. Again that's very analogous to the leak in a flare module example I gave earlier.

COMMISSIONER FOERSTER: That wasn't quite the question I asked, but.....

MR. HUBER: Okay.

COMMISSIONER FOERSTER: .....you make a nice point.

MR. HUBER: Could you rephrase then or.....

COMMISSIONER FOERSTER: Yeah, I'm going to.

MR. HUBER: Okay.

(Off record comments)

COMMISSIONER FOERSTER: My question was can you think of a situation where you would wish that you had this set of regulations in place and were following them?

MR. HUBER: If I may restate I would say no. But what I can say is that there's sit -- certainly there's situations where would I want to ESD a group of wells on high fire and -- or on a fire or gas detection, you bet.

COMMISSIONER FOERSTER: Okay. Well, could you describe for me your process for monitoring and responding that you do have in the long houses right now and any ways that it's different from what you have in single wellhouses?

MR. HUBER: Right now it is no different.

COMMISSIONER FOERSTER: It is no different. Okay.

MR. HUBER: The key differences are in how the long houses are constructed. Again there's partitions between wells, the long house design by agreement with the fire marshal incorporates things like firewalls, but in terms -- but they do not have fire and gas detection.

COMMISSIONER FOERSTER: Okay. Before I continue I wanted to say that I'm only asking questions -- you know, I said this incorrectly to Mr. Engel and I want to apologize for that. I'm only asking questions where I think that I can get clarity. If I think I already understand your point I'm not going to ask questions. And I -- when I said to Mr. Engel that I'd already made up my mind that was incorrect because that would be rude and inconsiderate and -- of you guys taking all the time for this. I certainly have not made up my mind. Sometimes Dan and John fuss at me for saying things I didn't mean, but this -- after I said it I wished I could have put it back into my mouth. So if I don't ask a question it simply means that I feel that I understand your point well enough that I don't need to delve into it more.

MR. HUBER: Okay.

COMMISSIONER FOERSTER: Okay. Let's see, let's go to (d)(2). So in -- when you -- your recommendation on (d)(2) is that you are recommending that we not require subsurface safety valves in any onshore wells. Okay. How many of your onshore wells currently have subsurface safety valve systems in percentage, rough?

MS. LOVELAND: In percentage working, 10 -- oh, 20 percent, 30 percent.

COMMISSIONER FOERSTER: 20, 30 percent?

MS. LOVELAND: Much less than 50.

COMMISSIONER FOERSTER: Less than 50 percent, okay, of your producing wells have.....

MS. LOVELAND: Yes.

COMMISSIONER FOERSTER: .....producing, injecting, working wells?

MS. LOVELAND: Yeah, wells in-service.

COMMISSIONER FOERSTER: Wells in-service. Okay. Okay. So where do you have them in service, you said that less than 50 percent have them in service.....

MS. LOVELAND: Yes.

COMMISSIONER FOERSTER: .....are they in a particular field or.....

MS. LOVELAND: Yeah.

COMMISSIONER FOERSTER: .....are they in a particular type of well or.....

MS. LOVELAND: Tyonek, offshore. Oh, I guess that doesn't apply, but that's where we have.....

COMMISSIONER FOERSTER: Onshore.

MS. LOVELAND: Onshore. Alpine, there's 200 and some wells there.

COMMISSIONER FOERSTER: Okay.

MS. LOVELAND: We have 3 Romeo pad which is within 660 feet of the ocean.

COMMISSIONER FOERSTER: Okay.

MS. LOVELAND: And at 1 Bravo pad which is near a billeted camp.

COMMISSIONER FOERSTER: Okay.

MS. LOVELAND: And there are other wells in the field that have had subsurface safety -- that have subsurface safety valves in the well itself, however they may or may not function because we do not test them.

COMMISSIONER FOERSTER: In your written co[illegible] about the volume of gas you -- that you vent du[illegible] valve system tests being wasteful. On an annua[illegible] you compare this to the volume of gas that you [illegible] annuli of the wells that you have with sustaine[illegible] pressure, is it more, is it less? You can get [illegible] it.

CPA never responded to this

MS. LOVELAND: Yeah, I'll have to get back to you because I really -- it would be hard -- we don't measure that volume,

COMMISSIONER FOERSTER: Do you measure the volume on -- that you vent during safety valve system tests?

MS. LOVELAND: No.

COMMISSIONER FOERSTER: Okay. And then a volume that you do measure that's pretty darn big is the volume that you report to us monthly in gas disposition reports and you might want to give me a comparison on that too.

On (d)(2) we use the word public and you use the -- you suggest that we switch it to general public. What's the difference?

MS. LOVELAND: In our wells, for example, near Beluga, there's a little community there and there's no gates, fences, any public could actually get near a well. And if it's just -- if it's general public then that's at large, if it's public it could be anyone.

COMMISSIONER FOERSTER: So if I had a house adjacent and my three year old wandered on, he would -- it wouldn't be your problem because he's not general public?

MS. LOVELAND: Maybe.

COMMISSIONER FOERSTER: Okay. That was my.....

MS. LOVELAND: It was just for clarification.

COMMISSIONER FOERSTER: Okay. Doesn't quite.....

MS. LOVELAND: It.....

COMMISSIONER FOERSTER: .....it doesn't clarify it for me. So if you think you might want to clarify it for me go for it.

MS. LOVELAND: At the time that we made the comment I do recall it had to do with Beluga and what was considered a public road and what was considered accessible to the public.

MR. HUBER: And, Commissioner, Jeff Huber here. We also struggled with even some more North Slope facilities and the definition of public. We have -- you know, there -- it's a private road system, we have roving security. Hopefully certainly we wouldn't have, you know, the problem of a three year old wandering onto the lease, but there are nearby villages where, you know, you couldn't rule without a doubt that somebody couldn't come onto the lease on a snowmachine. Again we have precautions, we have -- it's restricted access and what we -- our intent was to try and frame up that paragraph so that somebody couldn't say well, somebody could come in on a snowmachine or a helicopter and therefore it's accessible to the public. We're seeking clarity and apparently we didn't achieve that.

COMMISSIONER FOERSTER: Okay. That makes sense, but I don't see that general does that. Okay.

MR. HUBER: Fair enough.

COMMISSIONER FOERSTER: You talked about the difference between onshore hazards and offshore hazards and said that, you know, plane landing, stuff like that. Can you think of any other onshore hazards that might be less rare such as a truck hitting something or a big super sucker running into a wellhouse?

MS. LOVELAND: That's happened and the surface safety valve systems have worked.

COMMISSIONER FOERSTER: The surface safety valve system worked?

MS. LOVELAND: They had not affected the well such that it would require subsurface safety valve.

COMMISSIONER FOERSTER: Okay.

MS. LOVELAND: It would have to be a piece of equipment that was extremely large like a drilling rig.

COMMISSIONER FOERSTER: Okay. Which could happen. One more question on (d)(2). If we took your recommendation would Conoco go in and take all the SSSVs out, the subsurface safety valves out of the wells you have them in?

MS. LOVELAND: That would be cost prohibitive.

COMMISSIONER FOERSTER: Okay. On (e) you're recommending that WAG and MI wells do not need these requirements, is that correct?

MS. LOVELAND: Yes.

COMMISSIONER FOERSTER: Okay.

MS. LOVELAND: Based on the risk complement.

COMMISSIONER FOERSTER: Okay. What -- again what percentage of your WAG and MI wells are currently not equipped with subsurface safety valves?

MS. LOVELAND: All of Alpine is and 1 Baker pad and the rest of them may or may not have them based on when the well was drilled because back in 1981 they were required. However, if they're historic valves they may not work because we at this point do not test them. So percentage, we're back to the 20 -- I'm guessing, 20 percent. I can get you exact numbers if you would like.

COMMISSIONER FOERSTER: Okay. Less than 50 percent?

MS. LOVELAND: Definitely less than 50 percent.

COMMISSIONER FOERSTER: What -- for the WAG and MI wells that do have subsurface safety valves you say you're not testing them?

MS. LOVELAND: Only on the wells near a billeted camp.

COMMISSIONER FOERSTER: Okay. 1B.

MS. LOVELAND: And the ones near -- yeah, and near the ocean on the (indiscernible - simultaneous speech).....

COMMISSIONER FOERSTER: 1B and 3R would be the only ones?

MS. LOVELAND: Yeah, the 3R doesn't have MI. So.....

COMMISSIONER FOERSTER: Okay. So 1B is the only one that you're testing them on?

MS. LOVELAND: (Inaudible response)

COMMISSIONER FOERSTER: Okay. And do our inspectors witness those tests?

MS. LOVELAND: Yes.

COMMISSIONER FOERSTER: Okay.

MS. LOVELAND: Sometimes.

COMMISSIONER FOERSTER: All right. Let's move to (i)(7).

MS. LOVELAND: (Witness complies)

COMMISSIONER FOERSTER: I'm flipping pages, just a second. On this one is your concern that you don't like the use of the word remote or you don't understand what it is?

MS. LOVELAND: This is -- was asking for clarification as to exactly what was remote. Right now for ConocoPhillips it's our Beluga and Tyonek which are in the Inlet and it's for Alpine. That's what.....

COMMISSIONER FOERSTER: So you do you understand what it is?

MS. LOVELAND: That's what we think it means, but.....

COMMISSIONER FOERSTER: Has that been consistent with the behavior of the inspectors?

MS. LOVELAND: For my involvement in it, yes, however we have to be flexible with scheduling because there's usually only one inspector available at a time and they have many different directions to go.

COMMISSIONER FOERSTER: Okay.

MS. LOVELAND: But 48 hours generally isn't enough notice even with Kuparuk.

COMMISSIONER FOERSTER: Oh, so perhaps a longer notice would be helpful?

MS. LOVELAND: To them. A longer notice for us would be less beneficial.

COMMISSIONER FOERSTER: Okay. How about unannounced inspections, would that be better?

MS. LOVELAND: They're welcome anytime.

COMMISSIONER FOERSTER: I beg pardon?

MS. LOVELAND: I said they're welcome any time.

COMMISSIONER FOERSTER: Okay. So it would be okay with you guys if an inspector showed up and said let's do some safety valve tests, it's about time?

MS. LOVELAND: (Inaudible response)

COMMISSIONER FOERSTER: Okay. Okay. Let's go to (i)(10). Mr. Engel's already said that MMS doesn't use the standard that you propose. Do you guys have any idea why they don't?

MS. LOVELAND: No.

COMMISSIONER FOERSTER: Okay. And they do use a more stringent standard than.....

MS. LOVELAND: Less stringent than bubble tight though, isn't it? I don't know, I'm not familiar with the standard.

COMMISSIONER FOERSTER: It's more stringent than the one that you're proposing. Okay. All right. But you don't understand why?

MS. LOVELAND: No. The reason that we did propose this one is it's identical to what the Commission's proposing for the no flow leak rate, just for consistency so you have one reference document.

COMMISSIONER FOERSTER: Okay. Okay. Let's go to (j)(1), (2) and (3). You continuously man. What do you mean by continuously manned, that there will be someone on the pad.....

MS. LOVELAND: Uh-huh.

COMMISSIONER FOERSTER: .....and they may be engaged in other activities?

MS. LOVELAND: Continuously manned, that's your definition earlier.

COMMISSIONER FOERSTER: So it's someone who's on the pad, you know, maybe supervising a frac job someplace else or doing some testing on some other wells, but he's on the pad -- he or she is on the pad?

MR. HUBER: I think the definition -- I don't have the page in front of me, but as defined by the Commission it's physically on site and available to respond in the even of emergency, I believe.

COMMISSIONER FOERSTER: Available to respond. Okay. So.....

MR. HUBER: So.....

COMMISSIONER FOERSTER: .....you know, somebody could be on the other end of the pad doing something, but they would still be available to run over and respond?

MR. HUBER: Right.

COMMISSIONER FOERSTER: Okay. So explain to me how that would be as safe as having a working safety valve system?

MR. HUBER: Implied in the continuous manning provisions that already exist in (k)(2) are the fact that again by physically on site and available to respond that they're not say supervising a frac or some other critical operation to where there would be a substantial delay. It would be that they're on site, they're monitoring the equipment. The risk exposure is a narrow window of time. Again all that is implied. Now again not to debate whether it would be as safe, the point is certain provisions, again (k)(2), allow us to defeat, for example, the low pressure pilot for maintenance. And again we just -- we can't leave the pad, we have to remain physically on site. And again this was more of a consistency issue.

COMMISSIONER FOERSTER: Okay. Okay. Let's look at (j)(4). I'm going to ask you the same thing I asked Mr. Engel, if we took this approach would it address your concern, you can't get the wing valve to hold pressure so we approve an alternate valve. And you are able to get an alternative valve to work, we go about our business and don't worry about you until the next time we come to do a safety valve system test. But you're not able to get an alternative valve to work for the test and you have seven days to get it or the wing valve fixed. Is -- would that be an acceptable approach?

A

MR. HUBER: We will, of course, adapt and accept, you know, whatever ultimately is ruled upon, but, I guess, our position is that it's an unnecessary stipulation. Again the purpose is to test the SVS system and as long as we do that and, in fact, we may choose.....

COMMISSIONER FOERSTER: But if you can't get an alternative valve to test then you can't do -- to work, to hold pressure.....

MR. HUBER: Sure.

COMMISSIONER FOERSTER: .....then you can't do the test?

MR. HUBER: We could put in a blind. We could -- there's -- we could use any means of positive sealing devices to affect a satisfactory test. And that truly is our obligation.

COMMISSIONER FOERSTER: Okay. Well -- okay. That's what I meant. If you're able to perform the test successfully then fine, if you're not able to perform the test successfully then you have seven days to do so.....

MR. HUBER: And.....

COMMISSIONER FOERSTER: .....would that be acceptable to you?

MS. LOVELAND: Seven days after the 210?

MR. HUBER: It's less.....

COMMISSIONER FOERSTER: Within seven days of the inspector showing up and you doing the test and failing the test, failing to be able to perform the test.

MR. HUBER: Not being able to perform the test. It's not our -- I mean, our desire is to not prescribe that seven days or any number of days because again.....

COMMISSIONER FOERSTER: You're saying let's do -- as long as we can do it within the 210 days we're happy?

MR. HUBER: Yeah, as long as we can meet our obligation to test within 210 days by whatever means and again the number of positive sealing devices, then we have tested the safety valve system of that well.

COMMISSIONER FOERSTER: And you feel comfortable going out and not being able to test your safety system, but then feel that it's still safe?

MR. HUBER: Well, we didn't say we weren't going to test it, we will test it within the prescribed interval.

COMMISSIONER FOERSTER: Okay. Okay.

MR. HUBER: And I think in -- that was prescribed in paragraph (i)(3) which we have absolutely no problem with.

COMMISSIONER FOERSTER: (k)(1). Everyone's been waiting for me to crack a joke so here it is. What's the difference between service and normal service and could you give me an example of abnormal service, that last one was a joke, but what's the difference between service and normal service.

MR. HUBER: You want to take that one?

MR. KANADY: Yeah, I think this is in regards to when we're performing like a frac job and multiple sequences of well work are required. And so we may bring the well back on with the subsurface safety valve not in service and provide and do.....

COMMISSIONER FOERSTER: As part of a flowback or something?

MR. KANADY: Yeah. And do additional well operations on a well and then -- and then once the well's brought back onto normal service after the sequence of well operations is completed. That's what we were getting at.

COMMISSIONER FOERSTER: Okay.

MR. KANADY: Following completion of well work, well intervention or routine. So that's what we call nor -- I guess that would be our definition of normal service.

COMMISSIONER FOERSTER: Okay. Okay. Okay. On (m)(2), that was a good place for me -- you know, a few spots in your comments it appeared that you were suggesting that we take on wording that we already had. I'm wondering if you guys were looking at an older version of our regulations because (m)(2) is a good example. The word written that you suggest that we add is actually already in the version that we publicly noticed on the 14th of January. So, I mean, that was just kind of a comment that let's you know I'm not sure you were working off the most recent version.

MS. LOVELAND: That written was clarification, can e-mail be written, is email -- the comment below you have written, we're underlying it and.....

COMMISSIONER FOERSTER: Oh, you weren't suggesting that we add the words, you were just triggering yourself to.....

MS. LOVELAND: We wanted clarification whether we could actually use.....

COMMISSIONER FOERSTER: Yeah.

MS. LOVELAND: .....well, it -- this one may not even have applied to our op -- to ConocoPhillips, but will email suffice as written or does it actually need to be by letter?

COMMISSIONER FOERSTER: Written -- email -- I'm held accountable for anything I send in an email whether I want to or not. Okay. No, so if that was a question for clarification then yeah, that's good.

All right. I have a couple of more general questions. And I guess -- well, any of you who feels that they're -- that it's good for you can address them. The first one, I see that Mr. de Albuquerque's signature is on the cover letter of transmittal for your comments. Did Mr. Albuquerque read the attach -- all of the attached comments or just the cover letter?

MR. KANADY: I believe he reviewed the whole entire document, yes.

COMMISSIONER FOERSTER: Okay.

MR. KANADY: And our presentation.

COMMISSIONER FOERSTER: Okay. Well, in your general comments you state and I'll try to quote it, AOGCC has repeatedly communicated that the AOGCC will need additional inspectors to implement the new regulations. That's taken from your document. So my first question is this. What form has this communication taken and who has issued it?

MR. KANADY: Which paragraph's it in?

COMMISSIONER FOERSTER: It's the first one.

MR. KANADY: Oh, okay. Yeah, well, I guess we'll have to get back with you on that. I don't.....

MS. LOVELAND: I can answer anecdotally, but not specifically to this. But I do know that from an inspector side of the process there's not -- from the inspector side of the process they are spread very, very thin especially during exploration season. And it's their wish there were more inspectors available.

COMMISSIONER FOERSTER: Well, I think it's an overreach to say that just because the inspectors are spread thin that these regulations will require new inspectors and that it's our plan to get them because of these regulations. You know I don't -- the inspect -- the Commissioners don't normally testify, but you've put something on the record that I find offensive. And so I would like to respond to it. In fact, I think your comments challenge, you know, our fiscal responsibility as a Commission. But for the record our budget has called for six inspectors the entire time I've been here. We have not been able yet successfully to hire a sixth inspector. About the time that we were to do that one of our inspectors retired which kept us at five. We have currently had a ad out for inspector more than once, we've interviewed people more than once for inspectors, but we've been unsuccessful at getting them. The reason that, you know, I've always felt that we were low in inspectors here for what I would think that would be comfortable as evidenced by your complaints that it's hard to get inspectors for the witnessing and blah, blah, blah, blah. But I think that the reason that we're in need of a sixth inspector is not because of this set of regulations, but rather due to the fact that our operations have continued to expand throughout the state. We now have Alpine, we have Oooguruk, we have North Star, we have Point Thomsom. And we're being called upon to assist the DNR in overseeing the geothermal regulations. So I was very offended by the suggestion that this -- and the statements that we say that's our plan. So I really do want to get -- I want you to get back with me with the names of the people who have told you this and in what context because I suspect that either you took their words out of context or they hadn't had discussions with any of the Commissioners or our administrative budget manager.

All right. Let's move on unless any of you feel the need to respond to that.

Okay. You answered that question, I think. Okay. I think you answered that question. I think that's all I have for Conoco at this time.

CHAIR SEAMOUNT: Commissioner Norman, comments, questions?

COMMISSIONER NORMAN: Just a couple of questions. This will be short. From the standpoint of the public on gas detection, and I'm the public member, so my job is to try to represent the public of Alaska and ask perhaps sometimes simple questions. But a member of the public normally says I smell gas. So at what point in flowlines, gathering lines, transit lines, if at all, is there any additive or mercaptan or something that would allow human detection of a gas leak or is that evident pretty much to workers. In other words to what extent could a human being without aid and even all mechanical devices, could someone say gas? I mean I could in my home.

MR. HUBER: Right because they add.....

COMMISSIONER NORMAN: That's right.

MR. HUBER: .....odor.

COMMISSIONER NORMAN: So my question is is that possible and maybe the answer is no, it's not.

MR. HUBER: Is it possible for a human to detect gas without the aid of any sort of.....

COMMISSIONER NORMAN: That's right.

MR. HUBER: .....odor addition or.....

COMMISSIONER NORMAN: That's right.

MR. HUBER: .....an instrument?

COMMISSIONER NORMAN: Yes, uh-huh.

MR. KANADY: I think generally we treat that answer to be no although there are individuals that can say, you know I smell gas. And it -- you know, on further investigation with an instrument you can bear that out. But in general we don't rely on human -- the human nose to detect gas or any other potentially hazardous substance.

COMMISSIONER NORMAN: Good. And then just a comment. Mr. Kanady, I had asked about SVS, other states, stringent, you said I'll get back to you on that and I wanted to make it clear I was simply just seeking that if you had an opinion, but there's no expectation that you would have to research or find out or provide us with anything else. So that was merely to see if you had any sense on that and it doesn't require any further submission.

MR. KANADY: Commissioner Norman, I was simply going to contact our personnel in Houston to see what their opinion of that question was and get back with you, just.....

COMMISSIONER NORMAN: Well, you.....

MR. KANADY: .....for my own curiosity.

COMMISSIONER NORMAN: Okay. If you can do that. The more information we can get the better equipped we are to make good, sensible rules and the more we can learn about what's going on elsewhere. But that question was not intended to make extra work for you.

MR. KANADY: Okay.

COMMISSIONER NORMAN: Nothing further.

CHAIR SEAMOUNT: Okay. I don't -- any questions I had have been more than covered so I don't have any. Ms. Loveland, Mr. Huber, Mr. Kanady, thank you very much for your thoughtful comments.

MR. HUBER: Thank you.

MR. KANADY: Thank you.
MS. LOVELAND: Thank you.
MR. HUBER: We appreciate the time.
(Off record comments)
CHAIR SEAMOUNT: At this time I would like to ask if there is any other members of the public which -- who would like to comment? Hearing none, has -- does anybody have any questions they've written down that they'd like to pass to the bench? Hearing none at this point we will call Mr. James Regg to the stand and he is a petroleum engineer to the Alaska Oil & Gas Conservation Commission. But in the interest of redundancy, Mr. Regg, would you please tell us who you are for the record.
MR. REGG: My name is James Regg, it's R-e-g-g. I'm the Senior Petroleum Engineer here at the Commission. I also serve in the capacity as the supervisor for the inspector program.
Good afternoon, Chairman Seamount, Commissioners Foerster and Norman. Thank you for the opportunity to describe our process for addressing existing policies, guidance documents and rules in conservation orders.
Existing regulation 20 AAC 25.265 is vague in many areas of the Commission's expectations for a functional, well safety valve system and I'll refer to that as SVS in my comments. To that extent we have been -- there have been numerous written guidelines, policy statements and decisions rendered since the existing regulations first become effective in 1980. Mr.

Aubert has referenced several of those and had discussed that point. There also have been numerous interpretations and verbal communications addressing all aspects of the safety valve system regulations. To the extent deemed reasonable and with an emphasis on statewide applicability, the Commission Staff as incorporated the existing rules, guides and policies into the proposed regulations we are discussing today.

Our goal is to eliminate redundant and contradicting SVS requirements. To do so we recommend rescinding all existing guidance documents, policies and past Commission letters that were written to provide clarification about well SVS requirements. We are confident that these have been incorporated into the proposed regulations. We believe that there are some issues however such as component failure rate calculations and determining the -- what triggers an increased test frequency, the information required for the approval of a subsurface controlled subsurface safety valve, no flow rig up test procedures, et cetera, that are more appropriately addressed in new a guidance document. Such a document is intended to be published with an effective date to coincide with the effective date of the proposed safety valve system regulations.

The Commission also recognizes that there are some field specific approvals in existence. These are embedded typically in conservation order pool rules most often titled automatic shut in equipment and address specific setting depths of surface safety valves, the use of electrical submersible pumps and other types of requirements. The Commission has looked at all conservation, injection and storage orders and concludes that there are approximately 35 with references to safety valve systems, 15 of those have specific requirements that we believe should be retained. The remainder of the safety valve system rules and conservation orders will also be rescinded.

This process will, similar to the proposed guidance document I mentioned earlier, be timed so that the effective date of the revised orders will coincide with the effective date of the proposed regulation. Work on the guidance document and the orders is currently ongoing.

You've been provided a list or you will be provided a list if you haven't already received it of the affected conservation orders based on our review. I request that we provide that list to the public for their review also. We are interested in identifying any specific items that may have been missed by our review. The Commission contacts for this would be Mr. Winton Aubert and myself.

Thank you. I would also be willing to answer any questions that you may have on our process.

CHAIR SEAMOUNT: Commissioner Foerster.

COMMISSIONER FOERSTER: I don't have any questions on the process of how you're going to deal with the sea -- with the existing conservation orders, but I do have some other questions for you on some other things. I'll just wait and we'll get the process taken care of, but I think it would be good to see if any of the industry representatives have anything they'd like to say about the process, if this is an acceptable process to them or if they might help us with improving the process. Is that okay?

CHAIR SEAMOUNT: Well, Commissioner Norman, do you have any comments or questions before we go to that?

COMMISSIONER NORMAN: No.

CHAIR SEAMOUNT: Okay. Then that's fine.

COMMISSIONER FOERSTER: Okay.

MR. ENGEL: Thank you, Commissioner Foerster, for asking for questions. For the record my name is Harry Engel with -- representing AOGA today.

I think what MR. Regg just described sounds to be a very efficient way to address our concerns regarding the topics that Jim went through. And I like the concept of having industry be involved with reviewing and being part of that. And that will be productive, I think, that we do be part of that. So I think we support the approach just described by Jim Regg.

COMMISSIONER FOERSTER: Okay. Thank you.

CHAIR SEAMOUNT: Any other questions, comments.

COMMISSIONER NORMAN: I think you have Mr. Kanady.

COMMISSIONER FOERSTER: Oh, I think Conoco wants to.....

CHAIR SEAMOUNT: Mr. Kanady.

MR. KANADY: Yeah, this is Randy Kanady and I just have a general comment in regards to developing a new guidance document for the SVS regulations. And just to go on the record, our concern being is that no additional requirements, regulatory requirements, be included in that guidance document, just a documentation of things and expectations, but not a regulatory requirement.

COMMISSIONER FOERSTER: You've been heard.

MR. KANADY: Thank you.

CHAIR SEAMOUNT: Thank you, Mr. Kanady. Commissioner Norman.

COMMISSIONER NORMAN: Yes. And just an additional comment as to process. We certainly welcome and it's very helpful to have industry involved in the process, but we also need to reiterate that it is a public process and that members of the public, if they have comments, they're not only welcome to do it, they're invited to provide their comments. And then I think the way this is evolving and I think we will probably decide this as the end of this hearing, but it does sound to me like we will be coming forth with another draft which would entail another public hearing. And I think this is a placeholder, but at the end of this hearing I think we need to decide that, whether there will be a public hearing. I did hear, I believe, Ms. Moriarty ask that -- or perhaps it was Mr.

Engel, ask that before final regulations are adopted they be provided to industry. And my comment is precipitated by that because if they're provided to industry they're provided to all Alaskans and all Alaskans will have an equal opportunity to comment on them.

CHAIR SEAMOUNT: Would that be a continuation of this hearing or a new hearing?

COMMISSIONER NORMAN: I think we'd take advice from our Assistant Attorney General, but my thought would be that it's a matter of time. If we wish to recess now and leave the record open to some date certain, we could do it, but otherwise I think probably we're going to need renotice the hearing. Mr. Ballentine, do you have.....

COMMISSIONER FOERSTER: Well, let me try to influence your decision. It would be my preference that we recess and set a date because otherwise we'll be doing this until the cows come home. When was the first time we did this, before I got here.

Okay. That was my comment.

MR. BALLANTINE: Whether we have to renotice it just depends on how substantive the changes were that went to the public -- went out to the public already.

COMMISSIONER FOERSTER: Okay. But we can recess?

MR. BALLANTINE: We can hold the public comments open. I think it's -- it sounded to me Mr. Engel is going to provide information, Mr. Kanady is, there was some discussion about whether we were going to send questions to the North Slope Borough. So I've been assuming we're going to leave the public comment open. We can recess this and continue it with the understanding that if the changes that we may make to what's currently been noticed become substantive it may have to be renoticed.

COMMISSIONER FOERSTER: Okay. Okay. My preference would be to take the most expeditious path.....

MR. BALLANTINE: Yeah, I'm just saying that.....

COMMISSIONER FOERSTER: .....that allows adequate working. Okay.

CHAIR SEAMOUNT: Can we take a 10 minute recess. Okay. We'll be back at 12:35. Off the record.

(Off record - 12:25 p.m.)

(On record - 12:35 p.m.)

CHAIR SEAMOUNT: Okay. So I believe we have a few more comments and questions and I believe that's from you, Commissioner Foerster, is that correct?

COMMISSIONER FOERSTER: I have one more question for Mr. Regg. Mr. Regg, you've heard various operators describe their safety valve systems, how they're used, how they perform, how they're tested. Based on your experience and that of your inspectors is there anything that you heard that you feel the need to comment on or don't agree with and if so, go for it.

MR. REGG: There are a few things that I heard that I guess I would like to comment on. One is I heard a lot of comments and we've seen a lot of comments that really deal with some very specific issues. I just would point out again to the operators and anyone else that would be interested in it, the regulations clearly include a waiver and a variance clause. And that was designed to account for many of these specific things. One of the comments that was raised was normal service versus service and we get into defining these terms, but if it becomes a point in time where they feel like it doesn't fit within that regulation and they can justify that point, then they should be coming to the Commission. And we've -- I think we've demonstrated in past -- in our past experience that we'll seriously consider those and if they make sense we'll approve those variances. And we can typically turn those around in very short order. So that's the one thing that I heard very many specific comments about the provisions in our regulation.

The other thing I wanted to touch on was comments about the impact of the inspection program because of what's perceived as increased workload. Yes, there will be increased inspections, it will be required. We've queried our data, our wells data and we've identified an additional less than 150 wells that would be -- that would require inspections that we don't normally do inspections on again for safety valve systems. Interestingly within the areas of the Cook Inlet onshore and then again on the North Slope, the only areas that we haven't looked at would be the Barrow gas field and the Walakpa field. But we already do look at well safety valve systems at the Beluga field and have been looking at about 14 wells per visit. We've been looking at the Happy Valley Wells since 2005 and we also have been looking intermittently at the wells within the Ninilchik Unit. So it's not a complete representation of the safety systems, but we have started to look at some of the onshore systems. And those have been at the request of the operators to come and take a look at those systems.

So there will be an impact to the inspection program, but I think the number of wells, the frequency that we inspect wells, I don't believe that that's going to be a burden. And if we were able to add another inspector, you know, the fact that we have three inspectors that are strategically located on the Kenai Peninsula really opens up the opportunity to do those inspections on those wells.

The third point that I guess I would like to raise is the questions that have been elevated by the operators about the leakage rate. I have some real concerns about the accuracy of leakage rate measurements, particularly for safety valves. I heard Conoco say that these are small leaks and I also heard, you know, a lot of discussion about relying on alternate positive sealing devices, alternate (indiscernble) wing valve. The accuracy of your test is going to be the smallest chamber possible which is why we use the wing valve for testing the surface and subsurface safety valves. As you test something that could be a lateral valve several hundred feet away or even going back to a manifold building, I would question the ability to accurately measure those leakage rates at that point in time. MMS did a study several years ago and they contracted Southwest Research Institute to look at the ability to measure leakage rates because this has been an ongoing battle in industry for years. And what they found is that you just cannot accurately measure those things because of temperature, pressure, fluid issues that you don't have any control over while you're doing that safety valve test.

That's really what stood out to me today.

COMMISSIONER FOERSTER: Thank you, Mr. Regg. My last comment is just I want to acknowledge all of the thought, effort, hard work that a number of people throughout the industry and within this agency have put into these regulations.

Thank you all.

CHAIR SEAMOUNT: Commissioner Norman.

COMMISSIONER NORMAN: Does that finish all of your questions, Commissioner Foerster?

COMMISSIONER FOERSTER: Oh, I do have one more question for industry, Conoco more so than BP, but AOGA if you chose to.

Conoco, there were a number of cases where you cited additional costs and to the degree that you can do it without turning it into a term project, we'd appreciate a better understanding of what those cost impacts are. And not just a -- it'll be a lot or a few and many and not just a zillion dollars, but it'll be this much money in these fields for these activities. Does that make sense, we want to know what decisions we're making that will have an impact, to what degree and where. Okay?

MS. LOVELAND: Uh-huh.

COMMISSIONER FOERSTER: Thank you.

CHAIR SEAMOUNT: Commissioner Norman.

COMMISSIONER NORMAN: Yes. And in the record we did receive written comments, these are available to any of you that want to get them, comments from the North Slope Borough and Aurora Gas. The Commission may seek some clarification from the North Slope Borough or Aurora Gas and if any of you want copies of their responses please see the Commission's Special Assistant, Jody Colombie, in the back of the room, let her know and then we will see that those responses are provided to you. They will also be, of course, part of the public record, but if you specifically want to be sure you're copied if the Commission does decide to get clarification from them, let the Special Assistant know.

MS. COLOMBIE: Commissioner Norman, I provided this to AOGA yesterday, all of them.

COMMISSIONER NORMAN: Yes, thank you, Ms. Colombie. And now what I am referring to is if the Commission writes back to Aurora or the North Slope Borough it's their response that the public may be interested in.

CHAIR SEAMOUNT: Okay. One last opportunity for anybody from the public to comment, testify. Mr. Engel.

MR. ENGEL: Thank you, Commissioner Seamount. For the record my name is Harry Engel with AOGA. Just for clarity I want to make sure I leave here today with clear understanding on what we owe the Commission.

CHAIR SEAMOUNT: I was going to get to that.

MR. ENGEL: Okay. Shall I hold off then?

CHAIR SEAMOUNT: No, go ahead and continue.

MR. ENGEL: Okay. From AOGA's standpoint we owe the Commission a response to the commingling regulation we talked about earlier in the first part of the meeting today, our comments on the proposal. Other than that I don't have anything else I've written down regarding safety valve regulations that we owe the Commission.

COMMISSIONER FOERSTER: You -- I'd ask you to give me a reasonable amount of time for wells to stabilize.

MR. ENGEL: Okay. Very good.

COMMISSIONER NORMAN: Mr. Chairman, Commissioner Foerster, if I could also comment. Mr. Engel, if you have any further comments you want to share on costs also that would be welcome.

It's not in the owed category, but you'd be welcome to submit anything further.

MR. ENGEL: Thank you, Commissioner.

CHAIR SEAMOUNT: I had one final comment and that is everyone who testified today, we take your concerns and comments very seriously. We realize that you're very educated, very experienced, very intelligent people. So we really think about what everyone has been saying and we will think about it.

Do -- any final comments here?

(Whispered conversation)

CHAIR SEAMOUNT: What we're going to do for both issues concerning 20 AAC 215 and 20 AAC 265, we will leave the record open until Tuesday, March 30th for further written comments and answers to our questions that we just discussed.

(Whispered conversation)

If substantive changes will be made we're going to have to renotice for a final hearing. We'll just -- we'll have to see, you know, what goes on between now and the 30th.

So if there's no other comments this hearing is adjourned.

(Recessed - 12:45 p.m.)

C E R T I F I C A T E

UNITED STATES OF AMERICA)
)ss.
STATE OF ALASKA)

I, Rebecca Nelms, Notary Public in and for the State of Alaska, residing at Anchorage, Alaska, and Reporter for R & R Court Reporters, Inc., do hereby certify:

THAT the annexed and foregoing **Public Hearing** held on March 18, 2010 was taken by Lynn Hall, commencing at the hour of 9:00 o'clock a.m, at the Alaska Oil and Gas Conservation Commission of Alaska in Anchorage, Alaska;

THAT this Public Hearing, as heretofore annexed, is a true and correct transcription of the proceedings taken and transcribed by Lynn Hall.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my seal this 7th day of April 2010.

Rebecca Nelms

Notary Public in and for Alaska
My Commission Expires:10/10/10

STATE OF ALASKA
OIL AND GAS CONSERVATION COMMISSION
20 AAC 25.215 – Commingling or Production and Injection
And
20 AAC 25.265 – Safety Valves

March 18, 2010 at 9:00 am

NAME	AFFILIATION	PHONE #	TESTIFY (Yes or No)
Larry Greenstein	CVX	263-7661	No
Dana L. Olson			Yes
Kara Moriarty	AOGA	272-1481	yes
Winton Aubert	AOGCC	—	Y
Bowen Roberts	CPAI	2656040	No
MJ Loveland	CPAI	943-1687	Y
Jeff Huber	CPAI	659-7042	Y
Bob Christensen	CPAI	659-7535	N
Perry Klein	CPAI	659-7034	N
Gary Targac	"	659-7411	N
Dan Lewis	CPAI	265-1413	N
Darrell Humphrey	CPAI	659-7535	N
TAB BALLANTINE	AGO		N
HARRY ENGEL	BP	564-4194	Y
MIKE BILL	BP	564-4692	N
Chad Helgeson	Aurora	277-1003	N
BARBARA FULLMER	CPAI	265-1341	NO
RANDY KANADY	CPAI	263-4126	Y
Tom Maunder	AOGCC	793-1250	N
Tiffany Stebbins	Marathon	565-3043	N

J. S. de Albuquerque
Manager
Health, Safety & Environment

P.O. Box 100360
Anchorage, AK 99510-0360
Phone 907.263.4682
Fax 907.263.4438

ConocoPhillips
Alaska, Inc.

March 8, 2010

Mr. Daniel T. Seamount, Jr., Chairman
Alaska Oil and Gas Conservation Commission
333 W. 7th Avenue, Suite 100
Anchorage, Alaska 99501-3539

**Re: Amended Comments of ConocoPhillips Alaska, Inc.
Proposed Regulation Changes to 20 AAC 25.265**

Dear Chairman Seamount:

ConocoPhillips Alaska, Inc. (CPAI) appreciates the opportunity to provide input on the proposed revisions to 20 AAC 25.265 regulations addressing safety valve systems. CPAI's detailed comments are provided in the attachment document. CPAI previously submitted comments to the AOGCC on August 20, 2007 with respect to proposed changes to 20 AAC 25.265.

CPAI is committed to being a world leader in Environmental and Safety performance. CPAI believes that the Safety Valve System strategies applied in major Alaskan oil fields are already some of the most protective in the industry. This is largely due to the requirement in Alaska to install surface safety valves on all wells, which is a requirement not widely applied to the onshore industry. Making changes to the current requirements should be carefully considered and any changes need to address clearly defined risks, taking into consideration the potential frequency of an identified risk, the probable consequence of such a risk, and the potential impact of solutions proposed to mitigate an identified risk.

In cases where a proposed change eliminates an identified risk without introducing new hazards or unnecessary burdens, CPAI believes that the additional wellwork risk, man power requirements, capital cost, and potential rate and reserve impacts are justified. In some cases, CPAI has not, however, been able to identify a potential risk reduction resulting from some of the proposed changes and CPAI urges the Commission not to implement changes where an appreciable risk has not been identified nor a commensurate benefit realistically anticipated. The proposed regulation changes that CPAI has the most concern with are listed below. Please refer to the attached document for detailed comments on these proposed requirements.

20 AAC 265 (d)(2) fail-safe automatic surface controlled subsurface safety valve for onshore locations
20 AAC 265 (c)(5) linked safety valve system (SVS)
20 AAC 265 (i)(1) and (5) relating to performance testing
20 AAC 265 (i)(10) and (11) "bubble" tight performance test
20 AAC 265 (j)(4) positive sealing devices

Existing CPAI policy and practice require the installation of subsurface safety valves for hydrocarbon wells in close proximity to situations where hazards are identified or where environmental or human risk is increased, such as public access areas, major waterways or airstrips. These situations present recognized risks that are being addressed by current systems. For wells that do not pose an increased risk or are not in close proximity to identified significant surface risks, CPAI believes that the addition of subsurface safety valves will not reduce overall operating risks, especially if consideration is given to the counter-balancing increase in operational risks resulting from increased well work activities associated with subsurface safety valves.

The use of subsurface safety valves is a safety technique commonly applied to offshore installations because it is not possible to completely mitigate identified risks in the offshore area using only surface safety systems. Offshore risks include potential for catastrophic problems such as collisions with marine vessels or impacts by ice flows and severe storms. These events are compounded at manned offshore locations by limited options for egress. These catastrophic hazards are absent for onshore operations; however, surface safety equipment could be compromised when moving a rig on or off of a well. This risk can and has been mitigated by placing back-pressure valves in wells when moving rigs on and off. This practice has minimal impact on operations, but addresses the risks associated with the most likely cause of catastrophic damage to a wellhead and surface safety valve.

Implementing regulations for subsurface safety valves for onshore locations is a change that should be carefully considered, both for its impacts on Alaska operations and the industry-wide impacts it will have far beyond Alaska state boundaries. CPAI encourages the Commission to avoid restrictive regulations that prescribe solutions categorically, such as requiring placement of subsurface safety valves in all gas injection wells regardless of tubing size, injection rate or injection pressure.

Please find attached CPAI's detailed comments and proposed changes to 20 AAC 25.265. We look forward to discussing these comments and proposed changes during the public hearing on March 18, 2010.

Due to the magnitude of the work required and impacts on existing operations of the proposed changes to the surface safety valve regulations as currently drafted, CPAI requests that the Commission allow industry to comment on the Commission's final version of the draft regulations 20 AAC 25.265 prior to submittal to the Attorney General's Office.

We welcome the opportunity to discuss further any of the above comments with AOGCC staff.

Sincerely,

J. S. de Albuquerque
Attachment

20 AAC 25.265 is repealed and readopted to read:

General Comments:

Additional Regulations Notice Information:

Item #6 states that from a State perspective, "initial and annual costs are zero". CPAI believes that this is misleading as AOGCC has repeatedly communicated that the AOGCC will need additional inspectors to implement the new regulations. In addition, it is clear from the proposed regulatory text that there will be a significant increase in state oversight stemming from the proposed changes, particularly in the area of SVS Testing. The fact that the AOGCC's budget is paid for by collection of regulatory cost charges pursuant to AS 31.05.093 and hence not from the State's general budget does not mean the additional costs are zero. Those additional costs will be incurred by the AOGCC for increased labor and costs for travel to witness tests, and will be paid out of its budget, which is paid by the oil and gas producers. The AOGCC should provide the estimated additional costs it expects to incur if these regulations are promulgated so that the public, the administration and the oil and gas producers will know what the anticipated cost impact to the regulatory cost charges of these proposed regulations would be.

Significant cost will be incurred by oil and producers for performance testing if carried out the way the regulations are currently proposed. Additionally, the oil and gas producers and the State of Alaska will experience deferred production from longer shut-in times.

Terminology - AOGCC has consistently declined to accept, without explanation, previous public input requesting use of a consistent naming convention with another key state regulator (ADEC),regarding the term "flow line" versus "well line". It is somewhat helpful that the revised regulations have modified the term to "well flow line" in most cases, but there remain a few examples where the regulation is inconsistent and misleading due to the continued use of the terms "flow line", "common flow line", etc. These are noted below. CPAI has also conformed references in the proposed regulations to the "Commission" to be the currently defined term "commission."

Pad failure rates are not stipulated in the proposed regulations. Currently a 10 percent failure rate on a pad will put it into a 90 day testing schedule. CPAI proposes that a guidance document be provided that states the pad failure criteria and what is required to return to a normal testing frequency.

The current practice for scheduling AOGCC inspectors for SVS inspection is not optimal. CPAI gives AOGCC a 24 to 48 hour required notice. AOGCC should be able to either commit to the proposed time or waive witnessing the test.

CPAI requests that the AOGCC confirm that Conservation Orders ("COs") currently in place will continue to apply after the effective date of these regulations. CPAI recognizes

that AOGCC is reviewing applicable COs and requests that such review be expedited so that if and when the proposed regulations become final, all producers know the status of applicable COs.

20 AAC 25.265 Well Safety Valve Systems.

(a) A completed well must be equipped with a functional safety valve system (SVS) unless the well is

(1) a water source well;

(2) a disposal injection well;

(3) an observation well;

(4) shut-in; or

(5) suspended.

(b) Every SVS must have a surface safety valve with an actuator and a low-pressure mechanical or electrical detection device with the capability to shut in a well when the ~~well's flow~~ well line pressure drops below the required system actuation pressure, unless another type of surface safety valve system with that same capability is approved by the commission.

(c) An SVS must meet the following requirements:

(1) the surface safety valve must be located within the well's ~~production~~ tree or immediately adjacent to the well's tree;

CPAI Comment (c)(1) - The requirement for where a SSV must be located is more ambiguous than in previous drafts. It is not clear that an SSV mounted immediately outboard of a wing, as exists in some current setups, would be considered "within the well's production tree." In addition, the SSV requirement also applies to injectors, so, the term "production tree" is misleading.

(2) the low-pressure mechanical or electrical detection device must be installed on the well line for the well;

(3) the SVS control unit must be placed in a location that allows unobstructed control unit access for operation, maintenance, repair and inspection;

(4) for a producing well, a check valve must be installed in the ~~flow~~ well line upstream of the production manifold;

(5) ~~if multiple wells use a common flow line, the SVS controls must be linked so that an emergency shut-in of one well will immediately shut-in all wells sharing the common flow line;~~

CPAI Comment (c)(5): CPAI recommends, for reasons listed below, deleting section (c)5, which would require SVS systems to be linked if they use a common well line:

1. **Pilot operating pressures on these wells are already linked via the common well line and the SVS would close if well line pressure drops significantly.**
2. **At the Kuparuk River Unit, there are approximately 121 linked injectors and 17 linked producers. Most of the linked wells are MI-injectors, which use a common gas injection**

line. There are check valves at the wellhead on each injector to prevent backflow to the common well line.

3. **In CPAI's Alaska operations, common line pressure is typically monitored at the central processing facility and injection lines can be shut-in remotely.**
4. **Currently, it is CPAI's understanding that most systems are hydraulic and if SVS controls must linked as proposed in this proposed regulation, hydraulic hoses may be used to link hydraulic panels, which are minimally 20' to 40' feet apart. Use of such hoses would increase spill potential and performance problems due to weather conditions.**
5. **Operation of linked SVS wells presents a significant concern. There could be the need to defeat not only the SVS for a well undergoing wellwork or similar activity, but also the SVS of the well that shares the well line and the linked SVS. Inherently this will result in more overall aggregate risk, since more wells would be operated with defeated SVS(s) or else required to be shut-in unnecessarily. Alternatively, a more complex system design, which would allow isolation of one well's SVS and leave the other well(s) SVS(s) active, would be difficult to install and maintain in a manner that is consistent with many current, effective systems that use *one* valve to defeat the SVS. Fundamentally, the linked SVS requirement creates greater spill risk from linked hydraulic systems, and/or greater potential for process failures or human error because of the increased complexity of integrated systems.**
6. **This new regulation would require additional manpower to performance test these new systems.**
7. **A large capital investment would be required to comply with this new regulation. This additional complexity will result in increased cost. For injection wells, each producer would have to conduct an economic evaluation on the capital costs for facility modification to link the SVS. If the incremental recovery of the remaining EOR reserves does not justify the capital costs of the new system, then the injection to that drillsite would likely be shut-in and incremental reserves may be unrecovered. To make that analysis and potential under-recovery make any sense, the producers need to know what incidents and quantified risks are driving the implementation of this new requirement. CPAI requests that the AOGCC provide the AOGCC's analysis leading to this proposed requirement.**
8. **CPAI is not aware of any well line failures where a linked system, like the system being proposed, would have provided a benefit. If the AOGCC has such data, please provide it to the producers. If the AOGCC does not have such data, then, again, CPAI requests that the AOGCC provide the AOGCC's analysis leading to this proposed requirement, including the quantified risks.**

(6) in every well's SVS, a fusible plug or a functionally equivalent device must be installed near enough to the wellhead so that the well will be immediately shut in if there is a fire;

(7) structures containing multiple wells in a common area must have a gas detection system ~~and~~ or a fire detection system that will immediately shut-in all wells located within the structure; the foregoing does not apply to structures built in compliance with applicable building codes and applicable Appendices under 13 AAC 50;

CPAI Comment (c)(7): CPAI believes that this section would most logically apply to offshore installations and not pertain to wells with onshore multiple completions in a single wellbore serving different pools, or to onshore well houses known as "long houses". CPAI requests that the AOGCC clarify the application of the proposed c(7) regulation and if the AOGCC does intend for it to apply to onshore installations, please provide the analysis leading to the proposed regulation.

To align the proposed requirements of AOGCC with the current requirements of the State Fire Marshall, CPAI recommends adding the wording inserted above (underlined in red) at the end of the proposed regulation.

(8) SVS equipment must be maintained in good operating condition at all times and must be protected to ensure reliable operation under the range of weather conditions that may be encountered at the well site; and

(9) components of an SVS installed before {*effective date of regulation*} and subject to the requirements of 20 AAC 25.265(c)(1) through (c)(8) ~~require Commission approval~~ must meet those requirements within one year to remain in operation or obtain a waiver or variance from the commission.

CPAI Comment (c)(9): It is not clear how the AOGCC would handle the required approvals. The proposed requirement for AOGCC to 'approve' SVS/SVS Components "within one year", for components that were installed before the effective date of regulation would appear to mean every SVS will require "commission approval" within one year in order to remain in operation. For efficiency in implementation of this proposed requirement, CPAI recommends that exceptions be allowed by variance or waiver as provided in proposed regulation subsection (p).

(d) In addition to meeting the other requirements of 20 AAC 25.265, the following wells must be equipped with a fail-safe automatic surface controlled subsurface safety valve capable of preventing an uncontrolled flow of fluid from the well's tubing, unless another type of subsurface safety valve with that capability is approved by the commission:

(1) a well that is capable of unassisted flow of hydrocarbons to surface and that has an offshore surface location;

(2) a producing well that is capable of unassisted flow of liquid hydrocarbons to surface and that has an onshore surface location that is within one-eighth mile (660 feet) of:

(A) a permanent dwelling intended for human occupancy (such as a billeting camp or private residence),

(B) an occupied commercial building (excluding structures located within an existing oil or gas field),

(C) a road accessible to the general public,

(D) an operating railway,

(E) a government maintained airport runway,

(F) a coast line (at mean high water),

(G) a public recreational facility, or

(H) navigable waters as defined by the United States Army Corps of Engineers in 33 CFR Part 329.4 with boundaries defined in 33 CFR 329.11; and

CPAI Comments: It is CPAI's recommendation that proposed regulation d(2) be deleted because there have not been any cases where an onshore SSSV in Alaska has prevented or would have prevented a well control incident. However, there have been cases where maintenance work on SSSVs has created well control incidents. Alaska is one of the few areas in the world where onshore SSSVs are routinely used.

If d(2) is not deleted, CPAI recommends the proposed changes shown above for the following reasons:

1. **If a well is shut-in it should not require an operating SSSV, as per proposed regulation a(4).**
2. **The proposed requirement for SSSV for onshore locations should be specific to wells that flow liquid hydrocarbons because gas wells do not present a spill risk to navigable waters.**
3. **SSSV testing on gas injection wells would require the venting of gas, increasing VOC emissions. CPAI requests that the AOGCC consider that impact and include it in the AOGCC's analysis of the need for this proposed requirement.**
4. **CPAI requests that the phrase "a road accessible to the public" be clarified as shown above.**
5. **There is no specific exemption to the subsurface safety valve ("SSSV") requirement for wells equipped with downhole pumping equipment such as electric submersible pumps ("ESPs") and Surface Powered Jet pumps (SPJP) that may have unassisted flow. Packers are not typically run in producing wells equipped with ESPs, and based on prior a determination, that SSSV's were not required due to operational risk to the ESP systems. CPAI requests a specific exemption for wells equipped with ESPs and SPJP that may also have unassisted flow.**

(3) a well that the commission determines, after notice and an opportunity for hearing in accordance with 20 AAC 25.540, must be equipped with a subsurface safety valve.

(e) In addition to meeting the other requirements of 20 AAC 25.265, dedicated gas injection wells ~~injecting gas~~ shall be equipped with either a subsurface safety valve as stated in 20 AAC 25.265(d) or an injection valve capable of preventing back flow. Wells cycling between gas storage injection and production shall be addressed by the commission on a case-by-case basis.

CPAI comment: It is not clear what risk would be mitigated with a SSSV in a WAG well that a SSV does not address. The proposed requirement of having SSSVs on miscible injection wells would only reduce the risk of a catastrophic event that causes the wellhead and surface safety valve to be compromised. This could be caused by a large collision with an airplane or drilling rig that would severely damage the wellhead. Rig collision risks can be mitigated by a requirement to install a back pressure valve prior to moving a rig on a

well and the likelihood of other such events is extremely low. The highest risk to well control issues results from well intervention activities and the frequency of these activities is increased if SSSVs are required on all miscible injection wells.

For example, at the Kuparuk River Unit, situations where a SSSV prevented an incident have not been identified; however, SSSVs have caused some wireline incidents. Adding a SSSV requirement to MI wells at the Kuparuk River Unit would increase performance testing costs, wireline costs, spill potential, risk of wireline tools getting stuck across the tree, and capital cost without a clearly defined risk reduction. CPAI requests that the AOGCC provide the risk analysis and quantification upon which this proposed requirement is based.

Not all gas injection wells present the same risks. The large volume gas injection wells at Prudhoe Bay Unit have 7-5/8" tubing and inject approximately 250 MMSCF/D. The MI wells at Kuparuk River Unit have 3.5" tubing and inject 5-10MMSCF/D. The regulations should treat these wells differentially in proportion to the risks presented.

(f) If a well is being produced by artificial lift, the capability must exist to shut down artificial lift to the well.

(g) A well that was completed before {*effective date of regulation*}, that is subject to the requirements of 20 AAC 25.265(d) or (e), and that is not equipped with the functional hardware that would make a subsurface safety valve installation possible sooner, must comply with the provisions of 20 AAC 25.265(d) or (e) no later than the date that the well undergoes a tubing workover.

(h) Any subsurface safety valve required under 20 AAC 25.265 must be installed in the tubing string and located a minimum of 100 feet below original ground level (mudline datum for offshore wells), or if permafrost is present, below the permafrost.

(i) SVS testing is required; wells injecting water are exempt. SVS testing consists of function and performance tests. A function test is defined in 20 AAC 25.990(29). A performance test includes a function pressure test of the system's valves as defined in 20 AAC 25.990(28), and a function test of the mechanical or electrical actuating device. The SVS must be tested, using a calibrated pressure gauge of suitable range and accuracy, as outlined below:

(1) a well's SVS shall be ~~performance~~ function tested within 48 hours of when an SVS or one of its components is installed or replaced. In addition, if a SSV or SSSV is installed or replaced, a performance test is required;

CPAI comments (i)(1) – If a *performance test* (including leak-test of SSV) is required within 48 hours of an SVS or one of its components is installed or replaced, this will require a complete state test (i.e. *performance testing)* after minor maintenance such as when a pilot, hose, etc. is changed out. A *function test* should be prescribed by this proposed regulation, with a *performance test* only required when an SSV is replaced or installed.

(2) a new well requiring an SVS shall not remain in service ~~be operated~~ unless it passes a performance test within 48 hours of placing the well in service;

CPAI comments (i)(2): CPAI requests the wording above to add clarity.

(3) performance tests must be conducted semi-annually, not to exceed 210 days between tests, unless the commission prescribes a different testing interval based on test performance results;

(4) a well that is isolated from its well ~~flow~~ line or other production offtake mechanism need not be tested at the time of the required performance test stated in 20 AAC 25.265(i)(3), but the SVS must be performance tested within 48 hours of the well's return to service, unless the commission approves an extension of the time for testing;

~~(5) operations that directly affect SVS performance require a performance test within 48 hours after the well is returned to service, unless the Commission approves an extension of time for testing or the well is otherwise in compliance with 20 AAC 25.265(k);~~

CPAI comment i(5): CPAI recommends deleting i(5). Routine blocking of pilots should not require a performance test. CPAI requests that the AOGCC clarify that it is the SSV or SSSV and not other components that would trigger this proposed requirement. Operations requiring a performance test would be the change-out of an SSV or SSSV. A performance test should not be required for a pilot, component (hydraulic line) change-out or blocking of pilots for well service, as addressed in i(1).

(6) all performance test results must be verified by an operator's designated representative and submitted electronically to the commission no later than the 15th calendar day of the month following testing;

(7) at least 24 hours (48 hours, if the test location is remote from the nearest commission office) notice of SVS performance testing must be provided to the commission so that a commission representative can witness the test;

CPAI comment on (i)(7): Whenever used in these proposed regulations, CPAI recommends that the AOGCC define what "remote" means for notice purposes. It is not clear whether it refers to all situations that require air or water craft transport even if the time involved is short (a 15 minute helicopter flight) or if it refers to a time limit on how long it may take the AOGCC representative to travel to the site (i.e., what time period makes a site remote?).

(8) the system actuation pressure of the low-pressure mechanical or electrical detection device installed on a production well must be at least 50 percent of the separator inlet pressure or at least 25 percent of the flowing tubing pressure, whichever is greater;

(9) when an SVS is required, the system actuation pressure of the low-pressure mechanical or electrical detection device installed on gas injection wells must be greater than 50 percent of the injection tubing pressure;

CPAI comments i(9): If this regulation is also intended to be applied to water injectors, then significant negative impacts would result. For example, currently in the Kuparuk River Unit, water injection Low Pressure Pilots (LLPs) are set at 700 psig. The water injection system pressure is approximately 2500-2950 psig. To use an LPP set point of "50% of the injection tubing pressure" (1450 psi) would result in many wells' SVS tripping when a pump goes down at the CPF. This has the potential to cause equipment damage and frozen well lines. Many wells inject at less than 1500 psi, so the SVS would trip at the 1450 psig setting causing the well to shutdown prematurely. To mitigate this problem, a wide range of set points would be required, which becomes unmanageable in the field. This would create a wide range of set points throughout the water injection system. Water injection systems consist of an incompressible fluid, and the relative incompressibility of the water inherently means that sensitivity of the SVS is maintained even at lower trip pressures.

(10) within 2 minutes of the actuation of a mechanical or electrical detection device, a required surface safety valve must close <u>and meet API Standard 14H</u> leak off criteria ~~with no detectable leakage~~;

CPAI comments i(10) : CPAI believes that the reference should be to the API standard 14H 6.2.2 for leak rate 2 minutes from SSV tripping. Performing to zero leakoff criteria unnecessarily increases the cost of valve maintenance and replacements without any benefit.

(11) within 4 minutes of the actuation of a mechanical or electrical detection device, a required subsurface safety valve must close <u>and meet API Standard 14H</u> ~~with no detectable leakage~~;

CPAI comments i(11) : CPAI believes that the reference should be to the API standard 14H 6.2.2 for leak rate 4 minutes from SSSV tripping. Performing to zero leakoff criteria unnecessarily increases the cost of valve maintenance and replacements without any benefit.

(12) preventative maintenance records for the prior 6 months shall be made available at the request of a commission representative; such records shall indicate the date and type of SVS maintenance completed; and

(13) an SVS component fails a performance test when any test criteria in 20 AAC 25.265 (i)(8), (i)(9), (i)(10), or (i)(11) are not met on the first attempt.

(j) If a component of the SVS fails a performance test, the component must be repaired or replaced, or the well shut-in as follows:

(1) if the mechanical or electrical actuating device fails to actuate or actuates below the required trip pressure as determined with a calibrated pressure gauge of suitable range and accuracy, the actuating device must immediately be repaired or replaced and ~~performance~~ <u>function</u> tested, or the well must immediately be shut-in <u>or continuously manned as defined in subsection (k)(2) below</u>;

CPAI Comment (j)(1): A performance test cannot be done on an actuating device. Also, the proposed requirement should be consistent with part (k)(2), which provides that when a SVS is not fully operable, the well must be shut-in or continuously manned.

(2) for a well equipped with only a surface safety valve,

(A) if the surface safety valve fails to close, it must immediately be repaired or replaced and performance tested, or the well must immediately be shut-in or continuously manned; or

(B) if the surface safety valve leaks, the valve must, within 24 hours, be both repaired or replaced and performance tested, or the well must be shut-in or continuously manned;

CPAI Comment (j)(2) and (j)(3): These proposed provisions related to the situation where a SSV is not fully operable should be consistent with subsection (k)(2), which provides that in such situations the well will be shut in or continuously manned.

(3) for a well equipped with both a surface safety valve and a commission-required subsurface safety valve,

(A) if either the surface safety valve or subsurface safety valve fails to close, the failing valve must, within 48 hours, be both repaired or replaced and performance tested, or the well must be shut-in or continuously manned;

(B) if either the surface safety valve or commission-required subsurface safety valve leaks, the leaking valve must, within 14 days, be both repaired or replaced and performance tested, or the well must be shut-in; and

(C) if both the surface safety valve and subsurface safety valve fail a performance test, at least one valve must immediately be both repaired or replaced and performance tested in place, or the well must immediately be shut-in or continuously manned. The remaining valve must, within 14 days, be repaired or replaced and performance tested, or the well must be shut-in;

(4) if the positive sealing device used to test the SVS leaks or otherwise precludes a successful SVS test, such positive sealing device(s) must be repaired, replaced, or otherwise made functional and the SVS performance test conducted prior to the SVS testing interval expiration date provided for in (i)(3)~~, it must be repaired or replaced within 7 days.~~ Upon commission approval, testing may continue with a substitute valve.~~ Any SVS component that is not tested because of a leaking positive sealing device must, within 48 hours, be performance tested after the positive sealing device is repaired. The commission must be notified of the results and given 24 hour notice and an opportunity to witness a retest of the failed component. If the positive sealing device again leaks, preventing a definitive SVS performance test, the well may be shut in until the positive sealing device is repaired and it can be used for a passing SVS performance test. Performance of the first positive sealing device downstream of the SVS does not factor into decisions about test frequencies.~~

CPAI comments (j)(4): CPAI recommends the language changes shown above for the following reasons:

The time limits in (j)(4) appear to be arbitrary and overly-prescriptive rather than performance-based, and the provision attempts to regulate equipment that is outside the scope of this proposed regulation. The regulation governs the SVS system, but the wing valve (PSD) is not part of the SVS. The wing valve *enables* SVS testing, but is not the only device that enables testing as acknowledged in this proposed regulation. The proposed regulation prescribes an SVS testing interval in (i)(3) of *"not to exceed 210 days"*. As long as one or more PSD's enable an SVS Performance Test within that 210-day interval, compliance has been demonstrated. For example, testing is usually performed every 180 days. If there is a leaking PSD that precludes testing, there should be an additional 30 days to take whatever steps are necessary to execute an SVS performance test, and those steps would include repair/replacement of a PSD, not necessarily the first PSD downstream of the SVS. The proposed regulation language can and should be simplified to simply require that if leaking PSD(s) preclude testing, such PSD(s) should be repaired/replaced prior to the SVS testing interval expiration date.

(k) When required by a tubing workover, well intervention, or by routine well pad or platform operations,

(1) the subsurface safety valve may be temporarily blocked or removed; however, unless otherwise authorized by the commission, the subsurface safety valve must be made operable within 14 days of the date that the well is returned to normal service following completion of workover, well intervention, or by routine well pad or platform operations, and be tested within 48 hours of installation in accordance with 20 AAC 25.265(i); and

CPAI comments k(1): For well work requiring multiple operations, normal service would be at the end of the planned well work. CPAI suggests the changes shown above to add clarity.

(2) the surface safety valve and the mechanical or electrical detection device may be temporarily removed or defeated; however, unless otherwise authorized by the commission, the well pad or platform must be continuously manned, or the well must be shut-in, until the surface safety valve and mechanical or electrical detection device are made operable. Well pads, platforms, islands or similar groups of wells are "continuously manned" if sufficient responsible personnel are physically on-site and manually able to provide a level of protection equivalent to the removed or defeated SVS equipment.

(l) An operator may demonstrate by a no-flow test that a well is incapable of the unassisted flow of hydrocarbons to the surface subject to the following:

(1) a no-flow test must be performed according to commission-approved procedures, and to demonstrate no-flow, there must be a commission-witnessed three-hour period of no-flow;

(2) at least 24 hours (48 hours, if the test location is remote from the nearest commission office) notice must be provided to the commission, so that a commission representative can witness the test; and

(3) well work activities that have the potential to impact a well's flow capability will invalidate the well's no-flow status.

CPAI comment on (l)(2): As noted above, whenever used in these proposed regulations, CPAI recommends that the AOGCC define what "remote" means for notice purposes. It is not clear whether it refers to all situations that require air or water craft transport even if the time involved is short (a 15 minute helicopter flight) or if it refers to a time limit on how long it may take the AOGCC staff to travel to the site (i.e., what time period makes a site remote?).

(m) For purposes of 20 AAC 25.265(d), a well is incapable of the unassisted flow of hydrocarbons to the surface when:

(1) a witnessed no-flow test demonstrates that either

(A) the measured liquid production is not greater than 6.3 gallons per hour, and the measured gas production is not greater than 900 standard cubic feet per hour; or

(B) well pressure is discharged within five minutes after a three-hour charted pressure build-up period; and

(2) the operator receives written confirmation (including confirmation by email that is retained as a record by the operator) from the commission that the results of the witnessed no-flow test were accepted.

CPAI Comment (m)(2): It would be more efficient for both the operator and the AOGCC to allow email for written confirmation.

(n) If any required component of a well's SVS is inoperable, removed, or blocked, the well must be tagged. The tag shall identify the following:

(1) the inoperable, removed, or blocked component;

(2) ~~the date the problem was discovered~~;

CPAI Comment (n)(2): The proposed regulation appears to be redundant to n(3) and should be deleted.

(3) the date and reason, if known, that the component was inoperable, removed, or blocked; and

(4) the name of the person completing the tag.

Tagging is not required during well work activities and continuously manned operational activities that affect an SVS.

(o) The operator of each field shall designate and report to the commission a position as the single-point-of-contact. The single-point-of-contact is responsible for the following:

(1) ensuring that an SVS test schedule is coordinated with the commission;

(2) ensuring that actions consistent with these regulations are taken in the event of a ~~safety valve system~~ SVS failure and reported to the commission;

(3) ensuring that the commission is notified when an SVS has been repaired and is ready for testing;

(4) maintaining records of required SVS performance testing ~~tests, failures, repairs, and retests~~ for a period of at least five years; and

CPAI comment (o)(4): CPAI believes that the critical record is of the performance test, not the record keeping of the repair or function tests. Keeping records of the performance test is the critical issue since it includes both pass and fail test results.

(5) ensuring that the commission is notified if well conditions cause a change in SVS requirements, such as when a no-flow well is returned to flowing status.

(p) Unless notice and hearing are required under this section, upon written request from the operator, the commission may approve a variance from a requirements of this section if the variance provides at least an equally effective means of complying with the requirement, or a waiver of a requirement of this section if the waiver will not promote waste, is based on sound engineering and geoscience principles, will not jeopardize the ultimate recovery of hydrocarbons, will not jeopardize correlative rights, and will not result in an increased risk to health, safety, or the environment, including any freshwater as defined under 20 AAC 25.990(27).

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am 11/7/99, Register 152; am ___/___/____, Register, ____)

Authority: AS 31.05.030 AS 31.05.095

Alaska Oil & Gas Association
Testimony on Proposed Changes to 20 AAC 25.265 Well Safety Valves System Regulations
Public Hearing March 18, 2010

Harry Engel, Chairman of the Alaska Oil & Gas Association AOGCC Task Group

Good morning Chairman Seamount and Commissioners Norman and Foerster. My name is Harry Engel. This morning I am representing the Alaska Oil & Gas Association (AOGA) as Chairman of' the AOGCC Task Group.

I am the Engineering Team Leader responsible for Integrity Management in BP's Alaska Drilling & Wells organization. My responsibilities span all of BP's Drilling & Wells operations in Alaska. I hold undergraduate degrees in Civil and Environmental Engineering and have over 29 years experience in the oil & gas industry, primarily associated with drilling and wells activities. My assignments have included drilling engineering, well site leader roles and various Health, Safety and Environmental management positions. The majority of my experience has been in most of the operating areas in Alaska. I have also worked in the Rocky Mountains and have had several temporary international assignments.

This morning I will address AOGA comments submitted to the AOGCC on March 8, 2007 concerning the proposed safety valve system regulations. I request that the March 8, 2007 AOGA submittal be included in the public record concerning this subject. In addition I request that AOGA comments and testimony of August 20, 2007 and August 28, 2007 respectively be included in the public record.

I would like to acknowledge the following AOGA member companies who provided valuable resources and input into the development of our comments; Pioneer, ExxonMobil, ENI, Chevron, Marathon, and BPXA.

We would like to acknowledge AOGCC staff members Mr. Jim Regg , Dr. Winton Aubert and Mr. Tom Maunder for their efforts to enhance the understanding between the AOGCC and industry with respect to the proposed regulations.

In one respect, this morning I feel like Yogi Berra as I flash back to the August 2007 hearing on this subject…its deja-vu all over again. Then again, I also feel like Bill Murray in the movie "Ground Hog Day". Back in August 2007 I think I was sitting in this exact seat, before the same Commissioners, talking about the same topic. I'm confident the work done to date and the openness of the Commission to consider industry's comments will create a reasonable and clearly understood regulation.

AOGA members strongly believe that all oil and gas operations must be designed, constructed and maintained in accordance with sound engineering standards and practices. Our operations must provide a safe workplace, protect the environment in which we work and live and reduce overall risk.

The proposed regulation changes, which is about 5 pages in length are significant when compared to the current half page Automatic Shut-in Equipment requirements of 20 AAC 25.265. We are unclear to the actual safety benefit, risk reduction or reason for several of the proposed changes. Risk is defined as the product of probability and consequence. It would be helpful if the commission could provide tangible examples or justification that would support the changes. In some cases, additional risk could result with no incremental protection provided.

It is our understanding that one of the purposes of the proposed regulations is to standardize, streamline and provide clear and consistent requirements across the State and remove confusion associated with "legacy" documents related to safety valve systems. Since 2003, with the development of the AOGCC-AOGA Safety Valve System Taskforce, the Alaska oil and gas industry embraced the effort to bring clarity to the subject of safety valve systems. During the last hearing on this subject in August 2007, AOGA members submitted written comments and provided testimony. A major component of our comments related to AOGCC Conservation Orders, Guidance Documents, policies, procedures and legacy letters that address safety valve systems.

Examples of these documents include:

- **AOGCC Field Operations Procedure, No-Flow Test (4/24/92)**
- **AOGCC Policy SVS Failures (3/94)**
- **Safety Valve System Guidelines AOGCC Petroleum Inspection Group (8/12/98)**
- **AOGCC Letter to Operators 11/14/95: 6 month test interval, 10% failure rate**
- **AOGCC Letter to North Slope Operators 3/10/97: failures due to frozen SVS**
- **AOGCC Industry Guidance Bulletin No. 06-04, Subsurface Safety Valves**
- **Correspondence to operators regarding test reporting and failure calculations**
- **Correspondence to operators clarifying various SVS policies and guidelines**

Most of these documents are not available to operators on the AOGCC Webpage.

In addition, the proposed regulations do not address issues such as the impact to current Conservation Orders, calculation of pad failure rates, additional testing requirements and potential consequences.

Considering many of the issues raised in the August 2007 hearing have not been addressed, AOGA members are concerned that this effort will not meet the intended goal of providing clear and consistent regulations across Alaska. Alaska operators need to have clear guidance with respect to these issues to ensure operations are conducted in compliance.

I would like to address several sections of 20 AAC 25.265 Well Safety Valve Systems

The first area I would like to address is 20 AAC 25.265 (c)(5) which addresses "linked" safety valve systems.

We recommend that this section be deleted. It is unclear that there is a significant overall reduction of risk with a linked safety valve system over independent producing or injection well safety systems.

Producing wells sharing a common flow line are commonly equipped with independent safety valve systems. In these independent systems, a failure in the flow line reflected by a pressure decline is independently sensed by each well's low pressure detection device, actuating the independent safety valve(s). Facility modifications will be required to "link" the systems to conform to the proposed regulation. These modifications could involve piping or electrical work to run a hydraulic line or electrical connections between the wells, sometimes hundreds of feet apart. This "link" between the wells will require ongoing inspection and maintenance to ensure reliability. In addition, at low temperatures the increased viscosity of the oil used in hydraulic systems will reduce the reliability of linked systems.

For example, in Greater Prudhoe Bay there are approximately 100 groups of wells flowing into common lines. About half of these, or a minimum of about 100 wells, would require the modifications I just mentioned. It is anticipated that it would cost approximately $20,000 per well to "link" all these wells for a total initial cost in excess of $2,000,000. This does not include preventative maintenance and replacements costs. This is a fraction of the twined wells in service in Alaska that would be required to be "linked" under the proposed regulations. Considering we not aware of any situation where existing independent safety valve systems have not been effective, the significant incremental costs and questionable risk reduction benefit, we urge the Commission to reconsider the need for this section.

The next area I would like to address is 20 AAC 25.265 (d)(2).

This section identifies onshore well locations within one-eighth mile (660 feet) of certain areas that will be required to have fail-safe surface controlled subsurface safety valves.

This section could have significant consequences on current and future exploration and development of Alaska resources especially in Cook Inlet marginal gas fields. Cook Inlet fields operated by AOGA members and impacted by this regulation are Cannery Loop Unit (~18 MMcfd) and Ninilchik Unit (~50 MMcfd). Wells in these units are equipped with surface safety valves. Many of these wells are a) monobores (making the installation of an SSSV complex and expensive); and b) located in unpopulated areas, even though still falling within 1/8 mile of a public road or the coast.

The next area I would like to address is a recommendation to add a section; 20 AAC 25.265 (d)(3), related to production wells equipped with electrical submersible pumps (ESP's) or capillary strings.

There is no specific exemption in the proposed regulations to the subsurface safety valve (SSSV) requirement in wells equipped with downhole electric submersible pumps (ESP's) or capillary strings. For example, packers are not run in Milne Point Unit (MPU) producing wells equipped with ESP's based on the prior determination that SSSV's were not required per AOGCC Conservation Order (CO) 390. Findings in CO 390 are still valid for wells equipped with both ESP's and packers. I reference Findings 4 and 5 of CO 390: "... Packers impede the efficient operation of ESP wells. Efficient pump operation requires venting gas away from the pump to prevent operational difficulties and damage to the pump. ... Setting packers shallow to allow gas to accumulate in the annulus causes complications in killing the wells prior to well repairs or changing pumps." Approximately 35 ESP change out workovers are performed in the Milne Point Unit each year.

The use of SSSVs in wells with ESP's and capillary strings will limit the use of some technologies that would otherwise make marginal investments more attractive. For example, the use of through-tubing deployed pump systems can significantly reduce the cost of an ESP workover by providing a means of rigless pump change outs via slickline or coiled tubing. Through-tubing ESP systems cannot currently be run through standard SSSV equipment due to the drift requirements of the through-tubing components. These pump change outs can be required as often as every two years. When considering production operating costs for a large number of producing wells, the savings using new technologies can have a significant impact on project economics without increasing risk to safety. Use of these technologies extends field life, enhances recovery, and minimizes waste.

We request a specific exemption be placed in these regulations for wells equipped with ESP's and capillary strings.

The next area I would like to address is 20 AAC 25.265(d)(5) in AOGA's redline version.

NOTE: Considering our recommendation to move section (e) into section (d), the following comments refer to the numbering sequence in AOGA's redlined version of the proposed regulations.

For clarity, we suggest section (e) be moved under section (d) which addresses subsurface safety valves, becoming (d)(5). We understand the intent of this section is to require subsurface safety valves in dedicated gas injection wells and water-alternating-gas (WAG) wells while they are injecting gas. Risk profiles will vary significantly between large volume, high pressure dedicated gas injection wells, such as in Prudhoe Bay, used for reservoir pressure maintenance, and relatively low volume WAG wells used for enhanced oil recovery in other fields. The risks associated with operating and maintaining subsurface safety valves in low volume, high pressure WAG wells may be greater than any safety benefit from the valves. In these wells, the specific injection valve design will not be suitable for both water and gas injection service. This will require additional intervention operations to pull and replace the injection valve at each WAG cycle change, including times with high pressure gas in the well bore. Operators may request a waiver under section (p) in this situation.

The next area I would like to address is 20 AAC 25.265 (h) which addresses SVS testing.

In this section and consistent with current practice we have recommended including language that will allow a well to stabilize thereby providing adequate time for a SVS to thermally stabilize before testing.

The next area I would like to address is 20 AAC 25.265 (h)(10)(11) which addresses SVS testing.

API Recommended Practices (RP) 14B and 14H provide specifications for new or repaired surface and subsurface safety valves that are in service. We have reviewed these RP's and they are currently in effect. These specifications allow the indicated leak rates. The exact closing time for a SSSV may be impossible to determine thus it may be impossible to determine if detectable leakage is occurring in 4 minutes.

In AOGA's redline version, operators may choose to use the "no dectectable leakage" criterion or actually calculate or measure the leak rate. Portable gas meters are available and in use in to measure gas leak rates. They are similar to household gas meters. Liquid leak rates are determined by measuring the flow into a calibrated tank over a period of time.

The next area I would like to address is 20 AAC 25.265 (i) which addresses SVS components that fail performance tests.

The proposed regulations would require a failed SVS component to be immediately repaired or replaced. The phrase "immediately be repaired or replaced and performance tested" is not well defined. This also applies to sections (i)(1), (2), and (3). We request at least 12 hours to diagnose the problem and repair or replace the actuating device before requiring the well to be shut-in. Additional time is allowed in various conservation orders if the pad is continuously manned.

We recommend language changes to reduce confusion and to allow additional time for repair or replacement of valves if the pad is continuously manned.

The next area I would like to address is 20 AAC 25.265 (i)(4) which addresses positive sealing devices used in SVS testing.

Where redundant valves are functional, we recommend the positive sealing device be repaired or replaced within 14 days. The positive sealing device used to test the safety valve system is normally the wing valve on the tree. This valve is also the primary well control valve, so if the valve fails to seal, a work request is submitted to repair or replace the valve as soon as possible. However, the valve is not the only valve available for testing purposes or for controlling well flow, nor is it part of the safety valve system described in Section (c). Replacement of the valve may require more time than 7 days to schedule personnel and equipment to erect scaffolding, drain and purge the flow line, and to pressure test. Shutting in the well during this time period will cause unnecessary loss of production when the SVS has already been proven functional and effective.

General Comment

Considering the magnitude of the proposed changes, the extensive comments provided by industry and significant potential impact to operators, we recommend that industry have the opportunity to review the final draft version of the proposed regulations in a public forum before they are adopted.

Thank you for the opportunity to provide comments regarding the proposed regulations governing safety valve systems.
End

Proposed New Regulation (new language shown in **bold**):

20 AAC 25.215 Commingling of Production **and Injection into Two or More Pools**.

(a) On the surface, the production from one pool may not be commingled with that from another pool except if the quantities from each pool are determined by monthly well tests or by another method of determining pool production approved by the commission.

(b)Commingling of production within the same well bore from two or more pools is not permitted unless, after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission

(1) finds that waste will not occur, and that production from separate pools can be properly allocated; and

(2) issues an order providing for commingling for wells completed from these pools within the field.

(c) Injection into two or more pools within the same wellbore is not permitted unless, after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission

(1) finds that the proposed injection activity will not result in waste or damage to a pool, and that injection volumes can be properly allocated; and

(2) issues an order providing for injection into wellbores completed to allow for simultaneous injection into two or more pools.

#3

Colombie, Jody J (DOA)

From: Roby, David S (DOA)
Sent: Wednesday, February 10, 2010 4:05 PM
To: Roby, David S (DOA); Ballantine, Tab A (LAW); Colombie, Jody J (DOA)
Cc: Aubert, Winton G (DOA); Foerster, Catherine P (DOA); Maunder, Thomas E (DOA)
Subject: RE: Proposed change to 20 AAC 25.215

I just had a call from Harry Engle and Mike Bill representing an AOGA working group on this proposed rule change. They had some concerns with the rule because the version that went out with the notice still had "from" instead of "involving" but it appears that those concerns (they thought we were going to require a hearing any time they wanted to add a new source to the injection stream instead of being able to do this via admin approval) went away when they found out that we will be using "involving".

They did bring up an issue I hadn't thought of before and that was whether or not existing commingled injectors would be grandfathered or would we require the operators to come in for a hearing on the existing wells. I'm guessing they would be grandfathered but I am not sure.

They also mentioned that there will be significantly more comments from industry on the safety valve regulations, which is scheduled for hearing at the same time as this proposed change.

Dave Roby
(907)793-1232

From: Roby, David S (DOA)
Sent: Tuesday, January 26, 2010 2:50 PM
To: Roby, David S (DOA); Ballantine, Tab A (LAW); Colombie, Jody J (DOA)
Cc: Aubert, Winton G (DOA); Foerster, Catherine P (DOA); Maunder, Thomas E (DOA)
Subject: RE: Proposed change to 20 AAC 25.215

Tom brought up a good point on the proposed changes. He pointed out that you don't have injection 'from' a pool, you inject into a pool. So it may be more grammatically correct to change 'from' to 'involving' in (b) and (b)(1). So the reg would read as follows:

20 AAC 25.215. Commingling of production and injection

(a) On the surface, the production from one pool may not be commingled with that from another pool except if the quantities from each pool are determined by monthly well tests or by another method of determining pool production approved by the commission.

(b) Commingling of production **or injection** within the same wellbore ~~from~~ **involving** two or more pools is not permitted unless, after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission

(1) finds that waste will not occur, and that production **or injection** ~~from~~ **involving** separate pools can be properly allocated; and

(2) issues an order providing for commingling for wells completed from these pools within the field.

Dave Roby
(907)793-1232

From: Roby, David S (DOA)
Sent: Thursday, January 21, 2010 3:18 PM
To: Ballantine, Tab A (LAW); Colombie, Jody J (DOA)
Cc: Aubert, Winton G (DOA); Foerster, Catherine P (DOA)
Subject: Proposed change to 20 AAC 25.215

Tab and Jody;

I'd like to see about the possibility of piggybacking a proposed change to the above referenced regulation on the already scheduled hearing for proposed changes to the safety valve regulations on March 18th. The reason I would like to, if possible, add this to that hearing is that both regulations are in the Article 3 – Production Practices portion of our regulations so it seems like it would be a good fit to combine these two items in the same hearing. My proposed change is simple, just to add "or injection" to 25.215(b) and (b)(1). So the regulations would read as follows, with the added words shown in bold.

20 AAC 25.215. Commingling of production

(a) On the surface, the production from one pool may not be commingled with that from another pool except if the quantities from each pool are determined by monthly well tests or by another method of determining pool production approved by the commission.

(b) Commingling of production **or injection** within the same wellbore from two or more pools is not permitted unless, after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission

(1) finds that waste will not occur, and that production **or injection** from separate pools can be properly allocated; and

(2) issues an order providing for commingling for wells completed from these pools within the field.

The reason for proposing this change is that I believe at the time the existing regulations were written the potential for commingling of injection was not considered, whereas now commingling of injection is a reality. We have the same concerns relevant to prevention of waste and proper allocation of fluids between the two, or more, pools regardless of whether the well is used for production or injection and the proposed change will close a loophole that BP pointed out that as written the reg could be interpreted to apply only to production wells.

Thanks,

Dave Roby
Reservoir Engineer
Alaska Oil and Gas Conservation Commission
(907)793-1232

#2

STATE OF ALASKA **ADVERTISING ORDER** SEE BOTTOM FOR INVOICE ADDRESS	**NOTICE TO PUBLISHER** INVOICE MUST BE IN TRIPLICATE SHOWING ADVERTISING ORDER NO., CERTIFIED AFFIDAVIT OF PUBLICATION (**PART 2 OF THIS FORM**) WITH ATTACHED COPY OF ADVERTISEMENT MUST BE SUBMITTED WITH INVOICE	**ADVERTISING ORDER NO.** **AO-03014021**

FROM	AOGCC 333 W 7th Ave, Ste 100 Anchorage, AK 99501 907-793-1238	**AGENCY CONTACT** Jody Colombie PHONE (907) 793 -1221	**DATE OF A.O.** January 26, 2010 PCN
TO	Anchorage Daily News PO Box 149001 Anchorage, AK 99514	**DATES ADVERTISEMENT REQUIRED:** January 27, 2010 **THE MATERIAL BETWEEN THE DOUBLE LINES MUST BE PRINTED IN ITS ENTIRETY ON THE DATES SHOWN.** **SPECIAL INSTRUCTIONS:** Advertisement to be published was e-mailed	

Type of Advertisement **Legal** ☒ ☐ **Display** **Classified** ☐ **Other (Specify)**

SEE ATTACHED

SEND INVOICE IN TRIPLICATE TO	AOGCC, 333 W. 7th Ave., Suite 100 Anchorage, AK 99501	PAGE 1 OF 2 PAGES	TOTAL OF ALL PAGES$

REF	TYPE	NUMBER	AMOUNT	DATE	COMMENTS
1	VEN				
2	ARD	02910			

FIN	AMOUNT	SY	CC	PGM	LC	ACCT	FY	NMR DIST	NMR LIQ
1		10	02140100			73451			
2									

REQUISITIONED BY: J Colombie

DIVISION APPROVAL:

02-902 (Rev. 3/94) **Publisher/Original** **Copies: Department Fiscal, Department, Receiving**

AO.FRM

STATE OF ALASKA ADVERTISING ORDER SEE BOTTOM FOR INVOICE ADDRESS	NOTICE TO PUBLISHER INVOICE MUST BE IN TRIPLICATE SHOWING ADVERTISING ORDER NO., CERTIFIED AFFIDAVIT OF PUBLICATION (**PART 2 OF THIS FORM**) WITH ATTACHED COPY OF ADVERTISEMENT MUST BE SUBMITTED WITH INVOICE	ADVERTISING ORDER NO. **AO-03014021**

FROM	AOGCC 333 West 7th Avenue. Suite 100 Anchorage. AK 99501 907-793-1238	AGENCY CONTACT Jody Colombie PHONE (907) 793 -1221	DATE OF A.O. January 26, 2010 PCN
TO	Anchorage Daily News PO Box 149001 Anchorage, AK 99514	DATES ADVERTISEMENT REQUIRED: January 27, 2010 THE MATERIAL BETWEEN THE DOUBLE LINES MUST BE PRINTED IN ITS ENTIRETY ON THE DATES SHOWN. SPECIAL INSTRUCTIONS: Account # STOF0330	

AFFIDAVIT OF PUBLICATION

United states of America

State of ________________ ss

________________ division.

Before me, the undersigned, a notary public this day personally appeared ______________ who, being first duly sworn, according to law, says that he/she is the _____________ of ______________________________

Published at ________________________ in said division _________and state of ______________ and that the advertisement, of which the annexed is a true copy, was published in said publication on the _________ day of _________ 2010, and thereafter for ____ consecutive days, the last publication appearing on the _____ day of _____________, 2010, and that the rate charged thereon is not in excess of the rate charged private individuals.

Subscribed and sworn to before me

This ____ day of ____________ 2010,

____

Notary public for state of ______________________

My commission expires ________________________

REMINDER

INVOICE MUST BE IN TRIPLICATE AND MUST REFERENCE THE ADVERTISING ORDER NUMBER.

A CERTIFIED COPY OF THIS AFFIDAVIT OF PUBLICATION MUST BE SUBMITTED WITH THE INVOICE.

ATTACH PROOF OF PUBLICATION HERE.

STATE OF ALASKA
RE-NOTICE OF PROPOSED CHANGES IN THE REGULATIONS OF THE ALASKA OIL AND GAS CONSERVATION COMMISSION

The Alaska Oil and Gas Conservation Commission (AOGCC) proposes to adopt changes to Title 20, Chapter 25, of the Alaska Administrative Code, dealing with commingling of production.

AOGCC proposes to add language to 20 AAC 25.215 that will explicitly include commingled injected fluids.

You may comment on the proposed regulation changes, including the potential costs to private persons of complying with the proposed changes, by submitting written comments to the Alaska Oil and Gas Conservation Commission at 333 West 7th Avenue, Suite 100, Anchorage, Alaska 99501. The comments must be received no later than 4:30 p.m. on March 8, 2010.

Oral or written comments also may be submitted at a hearing to be held from 9:00 a.m. to 12:00 p.m. on March 18, 2010, at 333 West 7th Avenue, Suite 100, Anchorage, Alaska 99501. The hearing may continue beyond 12:00 p.m. to allow comment by those present before 9:30 a.m. The public comment period will close at the end of the March 18, 2010 hearing.

If you are a person with a disability who needs a special accommodation in order to participate in this process, please contact Jody Colombie at (907) 793-1221 no later than March 1, 2010 to ensure that any necessary accommodations can be provided.

For a copy of the proposed regulation changes, contact Jody Colombie at 333 West 7th Avenue, Suite 100, Anchorage, Alaska 99501, (907) 793-1221, or go to www.aogcc.alaska.gov.

After the public comment period ends, the Alaska Oil and Gas Conservation Commission will either adopt these or other provisions addressing the same subject, without further notice, or decide to take no action on them. The language of the final regulations may be different from that of the proposed regulations. YOU SHOULD COMMENT DURING THE TIME ALLOWED IF YOUR INTERESTS COULD BE AFFECTED.

Statutory Authority: AS 31.05.030.
Statutes Being Implemented, Interpreted, or Made Specific: AS 31.05.030.
Fiscal Information: The proposed regulation changes are not expected to require an increased appropriation.

DATE: 1/26/10

Daniel ~~T.~~ Seamount, Jr., Chair

ADDITIONAL REGULATIONS NOTICE INFORMATION
(AS 44.62.190(d))

1. Adopting agency: Alaska Oil and Gas Conservation Commission.

2. General subject of regulations: Commingling of Production and injection fluids.

3. Citation of regulations: 20 AAC 25.215(b) and 20 AAC 25.215(b)(1)

4. Reason for the proposed action: to make regulations current with recent technological improvements.

5. Program category and BRU affected: Alaska Oil and Gas Conservation Commission.

6. Cost of implementation to the state agency: Initial and annual costs are zero.

7. The name of the contact person for the regulations:
   Name: Dave Roby
   Title: Senior Reservoir Engineer
   Address: 333 W. 7th Avenue, Suite 100, Anchorage, AK 99501
   Telephone: (907) 793-1221
   E-mail: dave.roby@alaska.gov

8. The origin of the proposed action: agency staff.

9. Date: January 26, 2010

10. Prepared by: Jody Colombie

Jody J. Colombie
Alaska Oil and Gas Conservation Commission
(907) 793-1221

20 AAC 25.215 is amended to read:

20 AAC 25.215 Commingling of Production and Injection. (a) On the surface, the production from one pool may not be commingled with that from another pool except if the quantities from each pool are determined by monthly well tests or by another method of determining pool production approved by the commission.

(b) Commingling of production **or injection** within the same wellbore from two or more pools is not permitted unless, after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission

(1) finds that waste will not occur, and that production **or injection** from separate pools can be properly allocated; and

(2) issues an order providing for commingling for wells completed from these pools within the field. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am 11/7/99, Register 152; am ___/___/____, Register, ____)

Authority: AS 31.05.030 AS 31.05.095

#1

MEMORANDUM

State of Alaska

Department of Law

RECEIVED

FEB 0 1 2010

Alaska Oil & Gas Cons. Commission
Anchorage

To: Daniel T. Seamount, Jr., Chair
Alaska Oil and Gas Conservation Commission
Dept. of Administration

Date: January 28, 2010

File No.: JU2010201083

Tel. No.: 465-3600

From: Deborah E. Behr
Chief Assistant Attorney General and Regulations Attorney
Legislation and Regulations Section

Re: Regulations File Opening Re: 20 AAC 25.215: Commingling of Production Practices

We have received your memorandum of January 26, 2010 regarding the above-referenced matter, along with a copy of the proposed regulations and related documents. The project has been assigned to Tab Ballantine, Assistant Attorney General, phone number 269-5100.

Our department's file number for this project is JU2010201083. This file number should be used on any further correspondence pertaining to this project.

DEB:pvp

cc: Robert Pearson, Regulations Contact
Dept. of Administration

Jody Colombie, Special Assistant to the Commissioner
Alaska Oil and Gas Conservation Commission
Dept. of Administration

Ben Shier, AAC Coordinator
Office of the Lt. Governor

Randy Ruaro, Deputy Chief of Staff
Office of the Governor

Tina Kobayashi, Supervising Attorney
Oil, Gas and Mining Section

Tab Ballantine, Assistant Attorney General
Anchorage

MEMORANDUM

STATE OF ALASKA

ALASKA OIL AND GAS CONSERVATION COMMISSION

TO: Deborah E. Behr
Assistant Attorney General
And Regulations Attorney
Legislation and Regulations Section

DATE: January 26, 2010

SUBJECT: File-opening request for Regulations Project on Commingling of Production Practices (20 AAC 25.215)

FROM: Daniel T. Seamount, Jr., Chair AOGCC
Regulations Contact
Department of Administration DTS

We are requesting that you open a new file for a regulations project regarding changes in Title 20, Chapter 25, Section 215, of the Alaska Administrative Code, pertaining to Commingling of Production Practices for the Alaska Oil and Gas Conservation Commission.

Enclosed is a public notice, additional regulations notice information, and a draft of the regulations.

Please assign Assistant Attorney General Tab Ballantine to this project. Our contact person for the project is Jody Colombie at 793-1221.